Province of British Columbia

Northwest Economic Development Studies

Power Supply Options

Ministry of Industry and Small Business Development
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POWER SUPPLY OPTIONS

TASK FORCE ON NORTHWEST ECONOMIC DEVELOPMENT OPPORTUNITIES

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PREFACE

During late 1981 and early 1982 the Cabinet Committee on Economic Development made a series of fact-finding visits to Northwest British Columbia. In response to briefs presented by a large number of private citizens, corporations and public groups, the Cabinet Committee commissioned a report which would summarize the area's economic potential. That report "The Northwest Region, A British Columbia Regional Economic Study" was released on September 15th, 1982.

The September 1982 report states that the area north of the Highway 16/CNR northline corridor has substantial development potential based mainly upon the significant but largely undeveloped mineral resources. However, this area lacks virtually all of the necessary infrastructure to sustain early large scale development. Lack of transportation and municipal facilities and adequate power at reasonable cost are seen as significant constraints to development at the present time. The report noted that development of minerals and other resources will require substantial private and public investments - investments which can only be made after careful planning and consideration of alternatives.

In response to the September 1982 report, the Cabinet Committee on Economic Development directed an Inter-Ministry Task Force to begin work on a series of detailed studies on the northern part of the Northwest region (i.e. from Stewart to the Yukon border). These studies were undertaken to determine the scale and timing of potential mineral developments, and to identify options to supply power, transportation and community infrastructure in order to serve those developments. The Task Force was also asked to identify the social and environmental issues which might arise as development proceeds.

The product of these studies is a set of six Inter-Ministry Task Force reports plus a summary report which includes the findings of these six background studies. It should be emphasized that these studies do not represent a blueprint for development, but rather indicate priorities for future planning and development. The reports identify options and, as far as possible, the negative and positive factors associated with each option. Final decisions on any specific development options would be premature at this stage. Such decisions will have to await further analysis and more concrete private sector proposals for the development of the resources of the region.

Finally, it should be noted that during the course of these studies the mine development scenarios were refined as more information became available. These scenarios have been updated in the background reports where possible. However, in the power supply report and the transportation report, the analysis is based on the original hypothetical development scenario. The environmental overview report is based upon the early definitions of potential development options provided by the other working groups. The conclusions of these reports are not materially altered by the refined development scenario.

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SUMMARY

1. The Provincial Cabinet Committee on Economic Development, following a visit to Northern B. C., in late 1981 and early 1982 formed an interministerial task force to review the potential for economic development in the northwest of B. C.

2. The Task Force proposed a possible schedule of mine develcpments for the next two decades and B. C. Hydro agreed to report on the approximate cost of alternative power supply options for these mines. A map illustrating the mines and a table showing the proposed development schedule are on pages 3 and 15 respectively.

3. In order to maintain consistency throughout the different reports being written by and for the Task Force, Hydro's cost estimates treat the proposed mine schedule as fixed.

4. The following four power supply options are examined in Hydro's report:

   (a) extensions from B. C. Hydro's grid;
   (b) energy supply from a coal-fired thermal plant at Klappan;
   (c) hydro generation near mine sites:
      (i) More Creek for Schaft Creek mine and/or Stikine Copper;
      (ii) small hydroelectric generation where identified for other mines; and
   (d) diesel generators at mine sites.

5. The analysis in this report focuses on the cost to the economy as a whole of supplying power to a mine. i.e. the analysis is undertaken from a social benefit/cost perspective rather than a financial one.

6. There is no single preferred power option for all mines in the northwest.

7. The cost of transmission north of Dease Lake alone exceeds the cost of generating power at or near Cassiar and Adanac. Therefore, notwithstanding the possibility of extending transmission facilities southward from the Yukon to Adanac and Cassiar, it appears that small hydro plus diesel at Adanac and diesel at Cassiar are the least-cost power options.

8. In general, diesel generation is preferred to small hydro as an on-site source of electricity. The exception in this study was Adanac, where a particularly favourable hydro site was identified. Note that this relationship may be reversed if constant dollar diesel prices increase significantly.

9. On-site coal-fired generation is likely to be the least cost power option for Klappan mine, and it may, after further cost studies, turn out to be cost effective for some other mines as well.

10. Advanced construction of Hydro's More Creek Project without connection to the integrated system is likely to be the least-cost power option for Schaft Creek mine.

11. Stikine Copper is scheduled to open in the year 2000. Extensions from the grid at Bob Quinn Substation would be by far the least-cost power option for Stikine Copper if the mine opens after power is available from B. C. Hydro's Stikine/Iskut Development.

12. Advanced construction of transmission lines from Telkwa to the mines is unlikely to be an economic option.

13. If mine start-up dates are delayed until power is available from Hydro's Stikine/Iskut Development then this would likely be the least cost power option for all mines except those near the Yukon border and, under certain conditions, Sustut as well.

1. INTRODUCTION

The Provincial Cabinet Committee on Economic Development, following a visit to northern British Columbia, in late 1981 and early 1982 formed an interministerial task force to review the potential for economic development in the northwest of British Columbia. The intent is to identify significant constraints to the realization of this potential and to evaluate options for overcoming the constraints.

The region under study is shown on the map on page 3. For the purpose of analysis, the region is divided in two zones. The Southern Zone, centering on the Highway 16 corridor between Hazelton and Prince Rupert, is more populated and developed than the Northern Zone, centering on the Highway 37 corridor between Stewart and Cassiar. Also, the Southern Zone has more immediate development potential. While there are vast mineral resources in the north, this zone lacks virtually all of the necessary infrastructure to sustain early development of these resources. Lack of transportation and municipal facilities, and lack of adequate, low-cost power, are all significant constraints.

As part of the Government's study, B. C. Hydro has agreed to report on the cost of possible power supply options for mines in the Northern Zone. B. C. Hydro was requested to base its cost estimates on mine in-service dates proposed by the Government's task force. It is important to note that the ranking of power options can depend critically on mine in-service dates. This is explained more fully in Section 2.3, pages 6-7.

The analysis in this report focuses on the cost to the economy as a whole of supplying power to a mine. The question of who pays for this power is not discussed.

It is likely that if transmission lines are extended from the grid to mines then nearby towns will also receive power. However, in order to focus on the direct cost of power supply to mines, the cost of extending transmission facilities to towns is not discussed.

It is beyond the scope of B. C. Hydro's terms of reference to consider the implication of power costs for the viability of mine operations in the Northwest. However, this will be considered by the Task Force as part of the larger study on the Northwest.

It should be stressed that the costs used in this report are preliminary estimates prepared for this study by B. C. Hydro. They embody a number of simplifying assumptions (listed in Section 2.3) and are therefore meant to provide only a rough order of magnitude of actual costs. The purpose of comparing costs in this way is to distinguish those power options which merit further consideration from those which do not.

NORTHWEST REGION
MAJOR EXISTING AND POTENTIAL MINES IN THE NORTHERN ZONE

SOURCE: NORTHWEST DEVELOPMENT PLANNING: STATUS REPORT, OFFICIALS' COMMITTEE ON NORTHWEST ECONOMIC DEVELOPMENT, 17 JUNE 1982.

2. METHODOLOGY

2.1 Identification of Power Options

Electric power is currently supplied to the region north of B. C. Hydro's grid by Hydro-operated diesel generators and by privately owned generators.

To provide a new source of electrical energy to the Province, B. C. Hydro is investigating a major hydro-electric development consisting of four projects on the Stikine and Iskut rivers and on More Creek (henceforth referred to as the "Stikine/Iskut Development"). The preesnt program of studies would enable power to be obtained from the first of the Stikine/Iskut projects in 1994. Although power from these projects would be available to supply regional requirements, any decision to undertake the whole development would depend on overall provincial energy demand and on the relative merits of alternative supply sources. As a consequence, plans for industrial growth in the Northern Zone must consider both the availability of other electricity supply options and the feasibility of constructing part of Hydro's Stikine/Iskut Development to serve local loads.

The following four power supply options are examined in this report:

(a) extensions from B. C. Hydro's grid;
(b) energy supply from a coal-fired thermal plant at Klappan;
(c) hydro generation near mine sites:
    (i) More Creek[1] for Schaft Creek and/or Stikine Copper;
    (ii) small hydroelectric generation, where identified, for other mines; and
(d) diesel generators at mine sites.

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1 More Creek Project is the smallest of the four generation projects which make up the Stikine/Iskut Development.

The cost of developing More Creek for Schaft Creek and/or Stikine Copper mine and the cost of supplying power via extensions from B. C. Hydro's grid is examined for three different development scenarios:

(a) B. C. Hydro does not build the complete Stikine/Iskut Development;
(b) electricity from the Stikine/Iskut Development is available by 1 January 2000; and
(c) electricity from the Stikine/Iskut Development is available by 1 January 1995.

A further option which was not separately considered by this report is the partial construction of the Stikine-Iskut Development, i.e. construction of the two Iskut sites and and required associated Transmission to connect these sites to the grid. Although the unit cost of energy from the partial construction of the Stikine-Iskut development would be higher than from the whole development it would still be competitive with other potential sources of electrical energy in B. C. The advantage of partial construction would be the provision of a major source of power (935 MW) in the Northwest with connection to the grid with a considerably smaller commitment of capital than the total development.

2.2 Cost Estimation

Most of the costs given in this report are based on desk studies and are therefore to be regarded as tentative estimates. The only costs which are based on field work are those for More Creek, transmission associated with Hydro's Stikine/Iskut Project and transmission to Schaft Creek and Stikine Copper.

The following guidelines are incorporated in the costs used for this study:

- all costs are in constant 1982 dollars. 1981 cost estimates are converted to 1982 using an 11.5% inflation factor;
- costs exclude interest during construction and corporate overhead as well as grants, provincial taxes and licence fees and depreciation;
- net present values are discounted to 1982;
- social discount rates of 8%, 10% and 12% are used, as directed by the Ministry of Industry and Small Business Development;
- real price inflation is assumed to be zero except where specified.

The purpose of calculating costs this way is to reflect the cost of alternative power options to the economy as a whole; that is, to reflect the cost of allocating resources but not redistributing them between different sectors of the economy.

2.3 Procedures for Analysis

Power options are compared on the basis of their average energy cost, calculated over the life of each mine. Average energy cost, measured in mills/kWh, equals the discounted present value of total cost divided by the present value of energy demand.[2]

Average energy cost is used because mine start-up dates are uncertain and because, at least for some of our power options, average energy cost is unaffected by this uncertainty.

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[2] The equation for calculating average energy cost is derived in the appendix to this chapter.

An alternative to using average energy cost would have been to compare power options using the discounted present value of total costs. However, the latter varies with the start-up date of a mine. This implies that uncertainty in the provisional start-up dates provided for this study would feed into the calculation of power supply cost.

In contrast, average energy cost is determined independently of start-up dates whenever a source of power is constructed for a single mine. This would cover both diesel and remote hydro generation as well as transmission lines which supply only one mine.

In order to estimate average energy cost for each mine, the following simplifying assumptions are made:

(a) In cases where a single power facility serves mines which have different start-up dates, it is assumed that the entire facility is built by the time the first mine comes into operation. Staging the facilities to meet the load would improve the economics of a thermal plants relative to a hydroelectric facilities because in reality a larger proportion of construction costs would be staged for the former than for the latter.

(b) Costs are based on the mines continuing to produce at a uniform rate. A slowdown or temporary closure of a mine could have a major effect on the cost of energy.

(c) Voltages of transmission lines are assumed to remain the same regardless of the number of mines which share them. In the case of the line from Telkwa to Stikine, it is assumed that a 500 kV line would be built because this is what would eventually be required for the Stikine/Iskut

project. In the case of other lines, the voltage is sufficient to supply all ten mines. Although this assumption biases the cost of extensions upward if some mines drop out, this simplification should be sufficient to indicate the order of magnitude of the cost of power from the grid;

(d) With one exception (see next paragraph) the cost of substation and transmission line segments is divided equally between all the mines which require a particular line segment or substation. For example, the transmission line from Telkwa to Bob Quinn is required for all mines and therefore the cost of this line is divided equally between all mines. In contrast, the line from Bob Quinn to Mess Creek is required only for Stikine Copper and Schaft Creek mines. Hence, half the cost of this segment is allocated to each mine. Although this approach has a number of shortcomings, it is useful insofar as it identifies the relatively high cost of supplying remote mines such as Adanac with extensions from Hydro's grid.

The exception to the procedure described above is that, of the entire cost of transmission from a central coal-fired powerplant to Eaglehead mine, only the cost of an extension from Letain to Eaglehead is allocated to the latter. As explained in Section 5.2.6, this exception is made because, with the mine start-up dates provided for this study, the assumption described in the previous paragraph produces an improbable ranking of power options at Eaglehead.

(e) The dates of mine operation, given in Section 3.2, Table 1, are fixed;

(f) The earliest in-service date for new facilities is determined by physical constraints and all necessary approvals for construction will be obtained by 1 January 1983;

(g) If a mine start-up date precedes the availability of a particular source of power, then it is assumed that mobile diesel units are installed to supply power temporarily;

(h) Power will be available from Hydro's Stikine/Iskut Development in two of the three scenarios described on page 5; and

(i) The additional cost ot the economy of building facilities associated with the Stikine/Iskut project before they are required as part of Hydro's integrated system should reflect not only the cost of bringing ahead known expenditure but also the cost associated with the risk of building part of the project ahead of the rest. However, in order to keep the analysis simple, the first and not the second category of costs are included.

In conclusion, it is important to note that for many mines, the above assumptions crucially affect the relative cost of alternative power options. Therefore, determination of a least cost solution is complex even though we begin with the four seemingly straightforward options described on page 4.

APPENDIX TO CHAPTER 2

CALCULATION OF AVERAGE ENERGY COST

From page 6: average energy cost = discounted present value of total cost ÷ present value of energy demand.

The equation for calculating average energy cost is derived as follows:

A. Definitions:

1. PV_D: Present Value of energy demand.

$$PV_D = \sum_{i=1}^{n} \frac{D_i}{(1+r)^i}$$

Where i = year
Di = energy demand in year i
r = real interest rate
n = total number of years

2. PV_{TC}: Present Value of actual total cost

3. PV^1_{TC}: Present value of total cost when average energy cost equals 1 mill/kWh.

$$PV^1_{TC} = (1 \text{ mill/kWh}) \times (PV_D)$$

4. AEC: actual average energy cost

B. Show That:

$$AEC = \frac{PV_{TC}}{PV_D}$$

C. Proof:

$$PV_D = PV^1_{TC}$$

$$\frac{PV_{TC}}{PV^1_{TC}} = \frac{AEC}{1}$$

Therefore,

$$AEC = \frac{PV_{TC}}{PV_D}$$

3. POWER REQUIREMENTS OF MINES

In early 1982 the Inter-Ministry Working Group on Northwest B. C. reviewed the mineral and coal potential of Northwestern B. C.. On the basis both of this study and of data about production costs, ore grades and metal price forecasts, the Economic Analysis and Research Bureau of the Ministry of Industry and Small Business Development outlined a possible schedule of mine developments during the next two decades. B. C. Hydro was asked to use this production schedule as a basis for estimating the cost of power to Northwestern B. C.

The schedule includes eleven mines, shown on the map on page 3. Two of the mines, Granduc and Cassiar, are already in operation and the former is scheduled to close by 1988. Therefore, for the purpose of this report, it is assumed that Granduc mine will continue to use its existing steam generator.

3.1 Peak Loads and Annual Energy Requirements

B. C. Hydro's estimates of the peak loads and energy requirements of mines in the Northwest Development Study are given in Table 1. Estimates of the peak load at Granduc, Cassiar, Letain, Kutcho Creek, Adanac, Red Chris, Schaft Creek, Sustut and Stikine are consistent with projections made by the companies themselves.

The estimate of load at Eaglehead is based on the Ministry of Energy, Mines, and Petroleum Resources' suggested operating level of 10,000 tonnes per day and on the assumption that ore will be trucked to Kutcho Creek for processing. This assumption was used because of Eaglehead's proximity to Kutcho Creek (40 kilometres) and because Esso Minerals has not yet estimated the load requirement of Eaglehead.

The load for Klappan (i.e. 40 MW and 280 GWh for a 5 million tonne per year operation and 80% load factor) was proposed by B. C. Hydro engineering on the basis of electricity use for some existing and proposed mines. This works out to about 53 kWh/tonne. Other coal mining proposals appear to range from 25 to 60 kWh/tonne with a general tendency towards the 50 kWh/tonne figure.

For all mines, B. C. Hydro's peak load estimates are consistent with the projections of mine output provided for this study by the Ministry of Energy, Mines and Petroleum Resources.

A load factor of 80% is assumed for all mines. This assumption forms the basis for energy requirements given in Table 1.

Further simplifying assumptions concerning energy requirements are:

(a) Mine load estimates given in Table 1 represent the total load (industrial and residential) which is to be generated for the mine sites; and

(b) Mines will have a constant annual energy requirement, beginning from their start-up date. This implies that we ignore any gradual increases in the energy requirements of mines after they begin operation.

3.2 Duration of Mine Operations

Proposed start-up years and mine lives are given in Table 1. These were provided to B. C. Hydro by the Mineral Resources Working Group. For the purpose of maintaining consistency throughout the different reports being written by the Inter-Ministry Work Group, these dates are regarded as being fixed,

even though the start-up dates of some mines precede the estimated earliest feasible in-service date for some sources of power. In reality, however, the scheduling of alternative sources of power supply is likely to influence the start-up date of a mine.

Finally, it is assumed that the start-up year used for a mine implies a start-up date of 1 January of that year. For example, Kutcho Creek would be scheduled to open on 1 January 1987.

3.3 Present Value of Energy Requirements, by Mine

See Table 2.

NORTHWEST B. C. DEVELOPMENT STUDY

MINES: IN-SERVICE YEARS, OUTPUT AND ENERGY REQUIREMENTS*

MINE	YEAR OF START UP	ESTIMATED MINE LIFE	PEAK LOAD (MW)	ANNUAL ENERGY REQUIREMENT** (GWh)
Granduc (Cu)	Existing	to 1988	12	84
Cassiar (Asb)	Existing	to 1995	10	70
Kutcho Creek (Cu, Zn)	1987	12 years	13	91
Letain (Asb)	1990	15 years	10	70
Eaglehead (Cu, Mo)	1995	15 years	10	70
Adanac ($Mo S_2$)	1989	20 years	12	84
Red Chris (Cu)	1990	20 years	7	49
Sustut (Cu)	1996	8 years	10	70
Klappan Coal	1990	20 years	40	280
Schaft Creek (Cu, Mo)	1992	25 years	80	560
Stikine (Cu)	2000	20 years	55	385

* After incorporating the data in this table into all cost calculations, B. C. Hydro received a new estimate of mine lives for Adanac and Kutcho Creek. The former was revised to 30 years and the latter to 14 years. These new values are not incorporated in the report. In the case of Kutcho Creek, the change is unlikely to have a significant effect on the report's conclusions. For Adanac, the change reinforces conclusions based on the original data.

** 80% capacity factor for all mines.

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TABLE 2

NORTHWEST DEVELOPMENT STUDIES
PRESENT WORTH OF ENERGY DEMAND
BASED ON LIFETIMES OF INDIVIDUAL MINES
(GWh; Discounted to 1982)

Mine	Annual Demand	Discount Rate 8%	10%	12%
Cassiar	70	623	567	520
Kutcho Creek	91	504	423	358
Letain	70	350	273	216
Eaglehead	70	238	170	122
	231	1092	866	696
Adanac	84	573	451	360
Red Chris	49	281	214	166
Sustut	70	148	108	80
Klappan	280	1604	1223	946
Schaft Creek	560	2990	2156	1584
Stikine Copper	385	1022	648	419
	945	4012	2804	2003
Total	1729	8333	6233	4771

4.0 DESCRIPTION OF ENERGY SUPPLY OPTIONS

4.1 Diesel Plants

Diesel electric generating stations may be used either as the sole source of electricity at a mine or as a supplement to other sources of power. It is assumed that diesel generators would be used to supplement small hydroelectric facilities where these alone provide insufficient power. Also, as mentioned in chapter 2, it is assumed that diesel units are installed temporarily if the in-service date of a mine precedes the availability of a particular source of power.

The required generating capacity of diesel plants which provide the sole source of power to a mine is given in Table 3.

Following is a list of the basic assumptions used in preparing the diesel plant cost data:

(a) The diesel plant capacity installed at each mine is sized to meet the peak demand with one generating unit out of service.

(b) For plants up to 20 MW total, unit sizes may be 2000 kW to 4000 kW. Capital costs are based on 2500 kW units at a total installed cost of $900/kW including site preparation, building, diesel units and auxiliaries, and fuel storage. Overhead and interest during construction costs are not included.

(c) For plants from 50 MW to 100 MW, unit sizes may be in the 10 MW to 20 MW size. Capital costs are based on 10 MW units at a total installed cost of $900/kW for medium speed units burning light fuel oil, and $1800/kW for slow speed units burning heavy fuel oil. The availability and suitability for use of heavy fuel oil in the climate of Northwest B. C. would need to be

studied further, as well as the transportability of large units to these remote locations.

(d) Where diesel units are required for less than 15 years, mobile rather than fixed units may be installed at a cost of $800/kW. These units cost less than fixed ones because would be kept in enclosed trailers rather than in a powerhouse.

(e) Annual Operating Costs[3]

(i) Small plants and mobile units

Light Fuel Oil and Lube Oil	-	9.3¢/kWh
Operating and Maintenance	-	1.62¢/kWh

(ii) Large plants

Light Fuel Oil and Lube Oil	-	9.3¢.kWh
Operating and Maintenance	-	0.8¢/kWh
Heavy Fuel Oil and Lube Oil	-	6.2¢/kWh
Operating and Maintenance	-	0.8¢/kWh

Depreciation and taxes are not included.

(f) The life of both mobile and fixed diesel plants is assumed to be 20 years. Since those mines with fixed plants require them for 15-25 years, it is assumed that fixed plants have no salvage value after a mine closes. The salvage value of mobile units is assumed to equal $Y \div 20 \times \kappa$ where Y is the number of years left in the life of a diesel plant and κ is the plant's replacement cost.

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[3] October '82, Northwestern B. C., diesel prices are as follows:
(a) light fuel oil: 35.1¢/litre total of which 3.9¢/L is provincial tax. This translates into 10.5¢/kWh with tax and 9.3¢/kWh excluding tax.
(b) heavy fuel oil: 29.5¢/L total of which 3.9¢/L is provincial tax. This translates into 7.2¢/kWh with tax and 6.2¢/kWh exluding tax.

(g) Diesel plants are assumed to be located at each mine load centre. The costs for distribution systems are not included as these systems will generally be common to all electricity supply alternatives.

(h) A two-year construction period is assumed for the diesel plants:

(i) First Year - Engineering, design, site preparation, foundations, building and major equipment orders (40% of cost).

(ii) Second Year - Equipment deliveries, installation, testing and commissioning (60% of cost).

(i) Cassiar Asbestos has a diesel plant rated 15 MW. It is assumed that no new diesel plant would be installed and that annual operating costs for the existing facility are those given under item (e) above.

TABLE 3

NORTHWEST B. C. DEVELOPMENT STUDY

Demand and Generation Capacity
Where Diesel is the Only Source of Power

	Demand		Generating Capacity (MW)	
Mine	MW	GWh	Total	Firm
Cassiar	10	70	N/A	N/A
Kutcho Creek	13	91	17.5	15.0
Letain	10	70	12.5	10.0
Eaglehead	10	70	12.5	10.0
Adanac	12	84	15.0	12.5
Red Chris	7	49	10.0	7.5
Sustut	10	70	12.5	10.0
Klappan	40	280	50.0	40.0
Schaft Creek	80	560	100.0	90.0
Stikine Copper	55	385	70.0	60.0

4.2 Remote Hydroelectric Generation with Diesel Support

(see Map #2 - enclosed with report)

This section examines the cost of supplying mines with hydroelectric power generated at nearby sites. Where these sites are expected to provide insufficient energy, it is assumed that diesel units are installed as a supplement.

Small hydro sites were identified near all mines except Klappan, Schaft Creek and Stikine Copper. However, early development of More Creek, part of B. C. Hydro's proposed Stikine-Iskut project, is examined in section 4.3 as a possible source of power for Schaft Creek and/or Stikine Copper.

Sites were selected on the basis of map studies and cost estimates are based on correlation with known projects.

4.2.1 Small Hydroelectric Generation

Project Descriptions (Summarized in Table 4):

Cottonwood River (Cassiar mine)

This site, about 20 km southwest of Cassiar township, could provide water storage regulation for powerplant capacities up to 25 MW. However, as the mine requirements are considerably less a smaller installation has been assumed.

The project would have a 40-metre dam in a narrow rock canyon on the Cottonwood River, an 8,000-metre penstock and a 12.5 MW powerplant developing a head of 200 metres.

Turnagain River III (Kutcho Creek, Letain and Eaglehead mines)

This site is located just upstream of the junction of Cassiar and Turnagain rivers. The damsite is located at the head of a canyon and waterfalls, and could provide storage regulation for powerplant capacities up to 80 MW. However, as the requirements of the three mines that this plant would serve are considerably less, a smaller installation has been assumed.

The project would have a 60-metre dam on the Turnagain River, a 900-metre penstock and a 40 MW powerplant developing a head of 110 metres.

It is assumed that the entire hydro facility would be built by the time the first mine, Kutcho Creek, came into operation.

Surprise Lake (Adanac mine)

This site is located just East of Atlin Lake and could be used to develop most of the head available between Surprise Lake and Atlin Lake. A low dam at the outlet of Surprise Lake would provide adequate year-round storage.

The project would have a 17,000-metre canal, a 1,100-metre penstock and a 7 MW powerplant developing a head of 240 metres.

Unnamed Creek I (Red Chris mine)

This run-of-river site is located about 13 km southeast of Red Chris mine location. The creek drains into the Klappan River.

The project would have an intake, a 3,600-metre penstock and a 2 MW powerplant developing a head of 100 metres.

Todagin Creek (Red Chris mine)

This run-of-river site is located about 12 km south of the Red Chris mine location.

The project would have an intake, a 5,000-metre penstock and a 5 MW powerplant developing a head of 110 metres.

Unnamed Creek II (Sustut Mine)

This small run-of-river site off the Sustut River is the only one that could be identified near the mine location. Development of the site could be difficult because of salmon runs. Suitable power sites are not available in this area because the terrain is mostly level and forms the divide for several drainage basins.

The project would have an intake, a 5,000-metre penstock and a 3 MW powerplant developing a head of 100 metres.

TABLE 4

Northwest B. C. Development Studies

Preliminary Hydroelectric Project Data

Mine	Load MW	Hydro Site	Plant Type	Plant Size MW	Annual Energy GWh	Penstock Length m	Dam Height m	Gross Head m	Capital Cost 1982$ x 10^6
Cassiar	10	Cottonwood R.	Storage	12.5	80	8000	40	200	45
Kutcho Cr	13								
Letain	10	Turnagain R. III	Storage	40	250	900	60	110	150
Eagle Head	10								
Adanac	12	Surprise Lake	Storage	7	56	1100 plus 17,000 canal	10	240	33
Red Chris	7	Unnamed Creek	Run of river	2	8	3600	Intake only	100	12
		Todagin Creek	Run of river	5	18	5000	Intake only	110	30
Sustut	10	Unnamed Creek	Run of river	3	11	5000	Intake only	100	20

B. C. Hydro, Hydro Resources, Generation Planning Department, 14 September 1982

Generation Costs

Estimated capital costs for small hydroelectric generation are given in Table 4. Annual costs are assumed to be 0.5% of capital costs. This is based on the following breakdown:

Annual Cost Item	Percent of Capital Cost
Operation and Maintenance	0.15
Administration and General	0.05
Insurance	0.10
Interim Replacements	0.20
Total	0.50

A plant life of 40 years may be assumed for run-of-river projects and 70 years for storage projects. These are both longer than the mine life estimates, ranging from 8 to 25 years.

Roughly 10% of total capital costs are salvageable. Assuming a plant life of 40 years, the present value of salvaged plant is insignificant relative to the cost of small hydro generation. Therefore, the costs used for the economic analysis in chapter 5 do not include an allowance for plant salvage.

4.2.2 Transmission Aspects of Local Hydroelectric Development

Single-circuit 69 kV transmission lines are proposed to transfer power from the hydroelectric generating sites to the load centres and mines except for the Sustut mine which can be supplied using a single-circuit 25 kV distribution line.

All transmission corridors are selected on the basis of map studies following existing or proposed roads where convenient.

Transmission cost estimates are based on current unit cost data prepared for preliminary planning studies. If circuit routings proposed here are not practical, transmission costs will generally increase in proportion to the length of alternative routes.

4.2.3 Supplemental Diesel Generation

Assumptions used to derive cost data for supplemental diesel generation are described in Section 4.1, pp. 17-19.

Table 5, on p. 27, lists the electrical demands for each mine, the capability of the proposed hydroelectric projects and the required diesel generation to make up the deficiency in hydro generation. Full diesel capacity backup has been provided for those hydro plants which are run-of-river. Hydro plants with storage are provided with enough diesel capacity to make up capacity and energy deficiencies.

TABLE 5

NORTHWEST B. C. DEVELOPMENT STUDY

SUPPLEMENTAL DIESEL GENERATION REQUIRED

Mine	Demand		Hydro Available			Diesel Required	
	MW	GWh		MW	GWh	MW	GWh
Cassiar	10	70	Cottonwood River	12.5	80	-	-
Kutcho Creek	13	91					
Letain	10	70	Turnagain River	40	250	-	-
Eaglehead	10	70					
	33	231					
Adanac	12	84	Surprise Lake**	7	56	5	28
Red Chris	7	49	Todagin Creek*	7	26	7	23
Sustut	10	70	Unnamed Creek*	3	11	10	59
Klappan	40	280	-	-	-	50	280

*Run-of-river plants.

**Assumes that storage makes 7 MW available throughout the year.

4.3 Hydroelectric Generation at More Creek (for Stikine and/or Schaft Creek mines)

This section is divided into 3 parts which deal respectively with generation, transmission and supplemental diesel requirements.

4.3.1 Generation

Project Description

The More Creek damsite is located on More Creek about 1½ km upstream of its confluence with the Iskut River and about 10 km northwest of the Bob Quinn Lake Provincial Ministry of Highways camp adjacent to Highway 37. The damsite is located in a narrow steep-walled bedrock canyon at the downstream end of the much broader More Creek valley. The dam would be approximately 135 m high and could be either earthfill or concrete arch construction. The reservoir which would flood the More Creek valley would be 4100 hectares in size and would have approximately 1300 million m^3 of live storage. The project also includes the construction of a 37 m high dam on Forrest Kerr Creek to divert the headwaters of this creek into More Creek. With this additional water the project could have a capacity of 155 MW and would be capable of providing approximately 700 GWh per year on average. More Creek can provide a uniform energy load of 600 GWh/year under all water conditions.

Basis for Project Selection

The More Creek Project is the smallest of the four generation projects which make up the Stikine/Iskut Development. The Development also includes the transmission required to

connect the generation sites to the provincial grid. The timing of the first power from the Development is dependent on the receipt of approvals and the growth of the demand for power from the province as a whole. The earliest planned in-service date would be 1994.

However, construction of the More Creek Project to meet local needs could proceed prior to the overall Stikine/Iskut Development. The More Creek Project would require 5 to 6 years for construction. Prior to the start of construction, at least two years would be required for further investigations and design. Thus, if the program of studies required for an independent More Creek Project were started in early 1983 and if no additional time was required for licensing, the More Creek Project could be in service by 1991.

The size of the project, its location, and its possible timing make it suitable to supply electricity to Schaft Creek and/or Stikine mines.

Project Cost

The cost of developing More Creek on a stand alone basis is examined under the following three in-service date assumptions for the remainder of the Stikine/Iskut Development:

(a) An in-service date is indefinite and cannot be counted on;
(b) Scheduled in-service date of 1995;
(c) Scheduled in-service date of 2000.

The implication of the first scenario is that Schaft Creek and/or Stikine Copper would incur the entire cost of

developing and operating More Creek[4]. The second and third alternatives imply that the cost to the mines of early development of More Creek is simply the cost of:

(i) bringing forward construction of the facility; and

(ii) paying the average energy cost of the Stikine/Iskut Development after the year 1995 or 2000 respectively.

In order to keep the economic analysis simple, the above unit cost is calculated on the basis of the project's average energy capability. However, under this assumption, an amount of energy equivalent to the average energy capability must be sold in order to cover costs. This may be optimistic, especially in years when Hydro has surplus average generation capacity. Therefore, in reality the unit energy cost would likely be higher than the cost assumed here.

Under scenarios (b) and (c), it is assumed that More Creek would be pre-built to serve Schaft Creek but not Stikine Copper. This assumption is made because:

(i) under both the scenarios, power from the Stikine/Iskut would be available by the time Stikine Copper comes into service (i.e. year 2000); and

(ii) the average energy cost from the Stikine/Iskut Development as a whole is less than that from More Creek alone. As a result, there is no advantage to Stikine Copper if it pays for early development of More Creek rather than using power from the scheduled B. C. Hydro project.

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[4] Under the first scenario, the salvage value of More creek is assumed to be zero. This assumption is made because the alternative is to build a transmission line from More Creek to B. C. Hydro's grid (at Telkwa) and thus to operate More Creek for the remainder of its salvageable life. This costs more than assuming a zero salvage value.

Total capital costs for the More Creek project are $\$251.8 \times 10^6$ in 1982 dollars[5]. Annual operating costs are .49% of the total capital cost.

The estimated average energy cost of power from the Stikine/Iskut Development is:

Discount Rate	1982 mills/kW.h
8%	25
10%	32
12%	39

These costs are the sum of:

(i) an overall cost at the generation sites; and

(ii) transmission and substation costs from generation to both Stikine and Bob Quinn collectors. The overall cost of generation is calculated using a weighted average of the generation cost at each of the four generation sites - i.e. More Creek, Iskut Canyon, Stikine Canyon and Tanzilla. Costs at individual sites are weighted by the annual average energy capability of the site.

Cost Sensitivity

The costs of the More Creek dam and powerhouse are based on the provision of one generator and turbine unit which would be satisfactory if the plant were operated as part of the Stikine/Iskut development. However, independent operation would require at least two units to provide flexibility. While this will substantially increase

[5] B. C. Hydro estimate dated 7 September 1982.

powerhouse costs, total cost is not expected to increase to an extent which would affect the viability of the project.

4.3.2 Transmission from More Creek to Schaft Creek & Stikine Mines

Description

A single-circuit 230 kV transmission line is proposed from More Creek hydroelectric generating station to Mess Creek and from there to Schaft Creek and Stikine Copper mines, a distance of about 67 km. The proposed route will cross some difficult terrain according to a report prepared in 1981 for the mining companies involved in developments at Schaft Creek and Stikine Copper. As the line proceeds west from More Creek, the reservoir will force the transmission line onto steep slopes which are slide prone and avalanche swept. Steel tower construction and careful placement will be necessary to improve security. As the route proceeds north it will cross a barren bench at high elevation. Here also steel towers may be required to withstand possible high winds and heavy ice loading.

Based on preliminary field investigations conducted in 1981, this route was selected on the basis of minimum cost to supply both Schaft Creek and Stikine Copper as well as to avoid conflict with the proposed Stikine/Iskut hydroelectric project.

However, the time factor for various projects in the area may provide different route options. For example, if hydroelectric sites on the Tanzilla and Stikine River are developed before the mines, if road access to the mines is

from the north, and if a transmission line route along the south side of the Grand Canyon of the Stikine is environmentally acceptable, then a transmission route from the north may be preferable to provide better security. However, routes from the north are much more expensive if More Creek is the closest source of supply.

Although a 138 kV supply from More Creek may provide an acceptable standard of service to an 80 MW load at Schaft Creek, the combination of rough terrain, future possible development of Stikine Copper and the proposed use of 230 kV transmission to interconnect More Creek to the main grid at Bob Quinn Lake makes 230 kV the logical choice of transmission voltage for supply to Schaft Creek from More Creek.

Transmission Costs

Transmission costs are based on estimates prepared in 1981 at the request of mining companies interested in developing mines at Schaft Creek and Stikine Copper.

If total capacity requirements and load characteristics make 138 kV supply acceptable and this voltage level can be made available at the sending-end substation at reasonable cost, then 138 kV transmission costs would be 15-35 percent lower than 230 kV, depending on the type of construction, based on current unit cost estimates. If mine development occurs after the proposed Stikine/Iskut projects are completed a route from the north would provide better security at roughly comparable costs to supply from More Creek. Further field investigations would be required to confirm routing and costs.

4.3.3 Supplemental Diesel

If More Creek is built to supply only Schaft Creek or only Stikine Copper, then no supplemental diesel capacity is required. But, if it supplies both mines then 50 MW of diesel capacity are necessary to produce 345 GWh in critical water years. The estimate of operating costs for supplementary diesel generation is based on joint energy demand by the mines of 945 GWh (135 MW), with the diesel plant operating at 60% capacity and producing 245 GWh/year. (ref. discussion on p. 28)

4.4 Extensions from B. C. Hydro's Grid (see Map #1)

4.4.1 General Description of Transmission Network

If the area were to be served from the grid prior to construction of the Stikine/Iskut Development, then a 500 kV transmission line extension would be built from the existing Telkwa substation to the proposed Stikine collector. The earliest practical in-service date for this line, assuming an approved route is available by 1 January 1983, would be October 1990. In cases where the start-up date for a mine is before 1991, it is assumed that mobile diesel units would supply power until January 1991. Substation facilities and lower voltage transmission extensions are proposed as required to provide minimum cost single-circuit supply to all the mine loads specified in Section 3.1. The selected routes make provision for later construction of the proposed Stikine/Iskut Development as well as for supply to existing local communities. Estimates have been prepared so that, insofar as practical, costs can be separated for supply to individual mines. However, the network proposed here should be considered as

a package whose individual elements are not completely independent.

4.4.2 Basis for Choice of Transmission Corridors

The use of map studies to select transmission corridors was necessary given the constraints imposed on this study and this approach represents a major source of uncertainty for the 138 kV line estimates. No precautions were taken to avoid crossing privately-owned or reserved land in route selection and land costs are based on the use of Crown land in general.

Note that the lines shown on map #1 indicate general corridor alignment rather than specific circuit routing of the lines discussed below.

500 kV Circuit

Telkwa x Stikine - Presently, the technically preferred route for at least two of the three 500 kV lines proposed for the Stikine/Iskut Hydroelectric Development. Field investigations have reached a point where technical feasibility is no longer in doubt and relative costs for alternative routes are unlikely to change significantly.

230 kV Circuit

Bob Quinn x Shaft Creek/Stikine Copper - Preliminary field investigations conducted in 1981. Route selected on basis of minimum cost to supply both mines and avoidance of conflict with the proposed Stikine/Iskut Project.

138 kV Circuits

Meziadin x Stewart - Technically preferred route provided an acceptable method of crossing glaciated section is available.

Stikine x Sustut - Route via Stikine and Klappan Rivers rather than Highway 37 chosen to avoid conflict along restricted sections of the 500 kV line corridor into Stikine substation. Between Ealue Lake and Klappan mine, Klappan River route rather than the more direct route via the Little Klappan River was chosen for improved security during winter. The most direct possible route from Klappan Coal to Sustut was selected but field study may show that a longer route is necessary.

Stikine x Kutcho - Earlier maps from MEMPR show road access to Kutcho may be via Dease Lake and Cariboo Creek so this corridor was selected for the proposed 138 kV transmission line.

Stikine x Adanac - Route selected on the basis of lowest overall cost to supply both Cassiar and Adanac.

4.4.3 Basis for Cost Estimates

Power supplied through extensions from the B. C. Hydro grid involves the following costs to the economy:

(a) construction of transmission and substation facilities;

(b) cost of power at the grid; and

(c) installation of mobile diesel units in cases where mine start-up dates precede the earliest feasible in-service date of transmission lines and substations.

(a) Transmission

500 kV transmission line costs are based on estimates prepared in 1981 for internal B. C. Hydro use in evaluating the proposed Stikine/Iskut Project. The 500 kV line proposed from Telkwa to the Stikine substation makes provision for the Hydro's Stikine/Iskut project. This implies that the cost of the line would be over-estimated if the decision were made to build a lower voltage line with insufficient capacity to transmit power from the Stikine/Iskut development to the grid at Telkwa.

230 kV costs are based on estimates prepared in 1981 at the request of mining companies interested in obtaining power for proposed mines at Schaft Creek and Stikine Copper. 138 kV transmission line estimates are based on typical unit cost data specifically prepared for this study. These figures should be considered to be preliminary office estimates subject to significant change resulting from future field investigations.

Stations cost estimates have been specifically tailored to meet minimal standards for supply to typical mining loads. If firm supply is required or additional circuits have to be terminated stations costs may increase by more than a simple factor such as the addition of line termination costs.

These cost factors can be expected to change with time along with changes in mining developments so that the methods of supply proposed here may not represent the least cost alternative within a few years.

Transmission costs are very sensitive to variations in several of the factors used to estimate costs. A more specific answer requires specific data on the nature of the variation to be considered. Transmission line costs are roughly proportional to circuit length for a given type of construction and voltage level. This provides a yardstick for estimating the effect of route changes on transmission costs. Changes in voltage level may be necessary or desirable if the load forecast varies or special load characteristics have to be accommodated. Soil conditions and nature of the terrain traversed by the circuit effects the type of construction used and hence the cost. It can be noted that H-frame construction has been assumed for all 138 kV transmission in this study and that for sections where field study indicates wishbone construction is acceptable costs could be 20 to 25 percent lower. Clearing costs are also known to be sensitive to the amount of timber to be removed and to the overall level of construction activity. The availability of road access affects construction costs and the remoteness of the area affects both labour and material transportation costs.

(b) Cost of Power from the Grid

(i) Cost of Power at Telkwa

An average industrial rate for the forecast period is projected to be roughly 2.5¢/kWh in constant 1982

dollars. This is estimated on the basis of the 1981 ratio of B. C. Hydro's average industrial rate to overall average rate and the projection in Hydro's September 1982 "Projection of Electric and Gas Gross Load Requirements" which shows prices in the 1990's being at an early 1980's level in 1982 dollars.

It should be noted that this electricity price is calculated using a 3% discount rate.[6] In a predominantly hydroelectric system, with high initial capital outlay and relatively low operating costs, the average cost of energy from the grid should increase with the discount rate. This implies that the cost of power from Telkwa is somewhat underestimated. However, for most mines this underestimate is insufficient to alter the ranking of alternative power supply options. A note is made where it appears that the cost of power from Telkwa changes results significantly.

(ii) Cost of Power from the Stikine/Iskut Development

See p. 31.

(c) Supplemental Diesel Generation

Assumptions used to derive cost data for supplemental diesel generation are described in Chapter 4.1, pp. 17-19.

The following guidelines form the basis of supplemental diesel generation cost estimates:

1. mobile diesel units are installed at mines where the start-up date is earlier than 1991 (ie. the earliest

[6] The estimated long run real cost of capital to B. C. Hydro.

feasible in-service date for transmission facilities; ref. p 34);

2. mobile units are salvaged in 1991 (i.e. when transmission becomes available) at a value which presumes linear depreciation over a 20 year life of the unit.

As mentioned in the Introduction, the cost of extensions from the grid is considered both independently of the B. C. Hydro's Stikine/Iskut project and under the assumptions that the project will be in-service either in 1995 or in 2000. The cost of power under these alternative scenarios is calculated as follows:

1. It is assumed that power is available from either Bob Quinn or Stikine Substation after the Stikine/Iskut Development is available;
2. the cost of power at Bob Quinn and Stikine is assumed to equal the average energy cost of Stikine/Iskut power at these substations plus the cost of a collector station at Stikine to transform power for mines to the north and east of Stikine; and
3. power is purchased at Telkwa until the Stikine/Iskut Development is in service.

4.5 Coal-Fired Electricity Generated at Klappan

This section addresses the question: "Would it be feasible to provide an energy supply to the developments in the northwest by building a central coal-fired thermal generating station in the area?" One of the possible projects in the northwest is Gulf Canada Resources' Klappan coal property; a coal-fired power plant next to this proposed mine is described in this section because that is probably the least costly and most

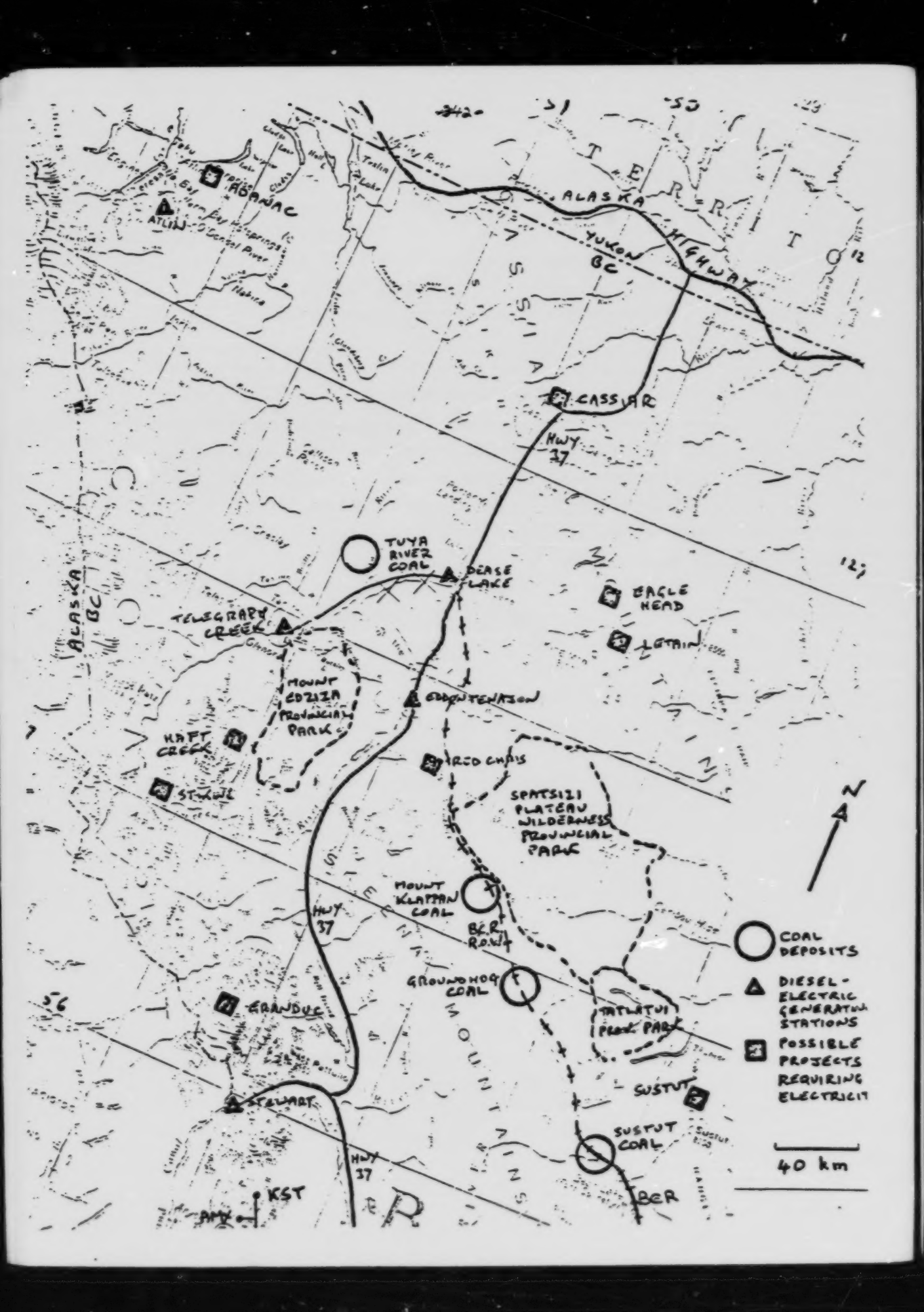
environmentally acceptable way of generating electricity from coal in the area. If such a project appears uneconomic compared with other energy supply options described in other sections of this report, then probably any other coal-fired power plant in the northwest would also be uneconomic; the associated transmission line costs would be approximately the same wherever the generating station was located.

This section is divided into three subsections. The first discusses coal-fired generation at Klappan. The second deals with associated transmission and the third examines the cost of supplementary diesel units for those mines where the start-up date precedes the earliest feasible in-service date for Klappan Generation.

4.5.1 Generation

Coal Resources in the Northwest

Figure 1 shows the four major known coal resources.


ALASKA
YUKON
BC
HIGHWAY
ATLIN
ADANAC
CASSIAR
HWY 37
TUYA RIVER COAL
DEASE LAKE
TELEGRAPH CREEK
EAGLE HEAD
LOTHIAN
MOUNT EDZIZA PROVINCIAL PARK
EDZIZ EXTENSION
KAFT CREEK
STIKINE
SPATSIZI PLATEAU WILDERNESS PROVINCIAL PARK
MOUNT KLAPPAN COAL
BCR R.O.W.
GROUNDHOG COAL
TATLATUI PROV. PARK
GRANDUC
STEWART
SUSTUT
SUSTUT COAL
KSTR
BCR
COAL DEPOSITS
DIESEL-ELECTRIC GENERATING STATIONS
POSSIBLE PROJECTS REQUIRING ELECTRICITY
40 km
N

(i) History[7]

No production has been achieved from any of the coal occurrences known in the northwest. Exploration for coal, however, has been carried out intermittently since the turn of the century. Most of the exploration activity has been concentrated on the Groundhog Coalfield.

The relative remoteness of the region has severely inhibited exploration and development. In recent years the construction of the Cassiar-Stewart Highway and the extension of the B. C. Railway subgrade through the Groundhog Coalfield has made difficult access less of a problem.

(ii) Klappan Activity

Gulf Canada Resources Inc. of Calgary, Alberta, own coal licences covering 14 784 hectares in the vicinity of Mount Klappan at the north end of the Groundhog Coalfield. They commenced initial exploration in the summer of 1981.

They have designed exploration programs spanning four and five-year periods culminating in a detailed feasibility study of a surface mine. Preliminary interpretation has indicated the probability of mining 1 to 5 Mt per year of anthracitic coal.

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[7] Dolmage Campbell and Associates Ltd., "Potential Coal Sources in B. C. for the Production of Substitute Natural Gas", January 1978.

(iii) Other Coal Deposits

1. Groundhog Coalfield

The Groundhog Coalfield[8], somewhat over 26 000 ha in area, lies in the Skeena Mountains. Several coal seams over 1.5 m thick are recorded in the succession and may have considerable areal extent. Extraction would most likely be by underground methods, although a few small areas may be amenable to open-pit operations. The coal is a semianthracite, which means that the coalification has proceeded to the extent that the coking and agglomerating properties of the coal are severely reduced. However, the coal has a relatively high heat content, i.e. over 27 800 kJ/kg (12 000 Btu/lb) on a dry basis (ash included), or approximately 32 500 kJ/kg (14 000 Btu/lb) on a dry mineral matter-free basis. Ash and volatile contents of the washed coal are generally quite low.

Willard D. Tompson, a geologist of Smithers, B. C., produced a report for B. C. Hydro in 1977 in which he concluded that it was not possible, considering the very early stage of exploration of the coalfield, to accurately calculate coal reserves or tonnages of recoverable clean coal.[9]

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8 Coal Task Force, "Coal in British Columbia, a Technical Appraisal", February 1976.

9 Willard D. Thompson, "Geology of the Groundhog Coalfield, Upper Skeena River Area, B. C.", March 1977.

2. Sustut Coalfield

No information regarding the extent, thickness or quality of the coals in the Sustut area is available.[10] Coal occurs in a belt 48 km long x 6 km wide bisected by the Sustut River.[11]

3. Tuya River Coal Deposits

Petro-Canada has studied coal deposits on the Tuya River, north of Telegraph Creek, and found three coals while conducting limited exploration.

Requirements for a Coal-Fired Power Plant

(i) Plant Location

It has been assumed that the least costly thermal generation project would be a coal-fired plant adjacent to Gulf Canada Resources' Klappan Coal project. Should this project prove uneconomic, it is probable that any other coal-fired thermal project in the area would also be uneconomic, particularly so if a coal mine exclusive to the generation project had to be developed as well as the generation facilities.

10 Dolmage et al, "Coal Resources of B. C.", 1975.
11 Dolmage et al, "Potential Coal Sources...", op cit.

The fourth figure in Gulf's Executive Summary[12] indicates that the best concentrations of coal were found adjacent to the BCR route in the northeast part of the licence area. The Spatsizi River is close to the BCR route at this point. The 1:50,000 maps of the area show adequately large areas for a powerplant between 4,000 and 4,100-foot (1223 and 1254 m) elevation in the area between the BCR and Spatsizi River.

It is likely that sufficient make-up water could be obtained from the Spatsizi River at Klappan. No streamflow measurements have been published for the river, but it can be estimated that its average flow is about 2 m^3/s, with a minimum flow of about 0.2 m^3/s in March. To put this into perspective, a 250 MW plant[13] at 67 percent capacity factor using cooling towers to reject the heat from the condensers would require about 0.1 m^3/s of make-up water. If actual streamflow measurements should show that the Spatsizi River is inadequate in this location, a much larger flow of water, about ten times larger, would be available at the confluence of the Spatsizi River, Didene Creek and Kluayetz Creek about 4 km away.

Other factors affecting the plant location would include meteorological conditions to ensure adequate dispersion of plant emissions, proximity to the coal source, adequate soil conditions for foundations, and an access corridor for a road and transmission lines. A possible transmission line network is shown on Map No. 3.

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12 Gulf Canada Resources Inc., "Mount Klappan Coal Project, Executive Summary", March 1982.

13 Sufficient to supply all ten mines in this study (i.e. excluding Granduc.)

Gulf Canada Resources Inc. have planned their townsite around the BCR right-of-way just south of their coal licence area. It is assumed that B. C. Hydro could house staff in this townsite.

(ii) Environmental Concerns

It has been assumed that Gulf Canada Resources' 5 Mt per year surface coal mining operation would go ahead and that the thermal plant would be located adjacent to it. The impacts of the mine on the comparatively untouched region around it would be very local except for the socioeconomic impacts. The additional impacts from a thermal project would include:

- impacts from flue gas emissions;
- impacts due to river water extraction; and
- impacts due to the additional people needed for the power plant.

The proximity of Spatsizi Provincial Park (the boundary would be about 3 km north and east of the power plant) could cause closer examination of project impacts than might otherwise be the case.

None of the impacts would appear to be so serious as to prohibit the project. However, a series of studies, including detailed environmental studies leading to an Environmental Impact Statement, would probably be conducted before applying to the B. C. Utilities Commission for an Energy Project Certificate.

(iii) Project Schedule

As noted in Chapter 2, Page 9, it is assumed that all necessary approvals for construction are obtained by 1 January 1983. On the basis of design and construction durations for Hydro's East Kootenay Project, the economic analysis in Chapter 5 assumes a 1 January 1990 in-service date for a coal-fired powerplant at Klappan.[14]

(iv) Project Economics

Capital Cost

There can be considerable variations in estimates of the cost of coal-fired plants depending on plant size and site specific conditions. Therefore, the cost estimates given below should be treated as preliminary, and provide a range within which actual costs are likely to fall. For the purposes of this report, it is important only to discern whether coal generation is likely to be cost effective relative to other power options and whether, as a consequence, further cost studies are warranted.

Examination of recent cost data for coal-fired power plants in Western Canada suggests a price range from 1220 to 3300 $/kW in 1982 dollars for this study. The low end of the range is probably not attainable in B. C. because of the more stringent perceptions and regulations affecting the environment and the generally greater expense for construction labour.

[14] Subsequent to completion of the economic analysis, the in-service date was revised to mid 1990. This would tend to increase the cost of the coal thermal option at mines which are scheduled to start up before mid-1990 because it is assumed that mobile diesel units would be installed during the period between mine start-up and mid-1990.

The actual cost will further depend upon:

- the capacity and number of units in a powerplant;
- the coal characteristics;
- site conditions;
- environmental regulations, expecially those affecting emissions of flue gases;
- market prices for equipment and labour.

In general, the cost per kW increases as the unit size decreases and the number of units increase to achieve a given total output.

It is unclear at this point what capacity and how many units would be required at Klappan. Therefore, for the purposes of this report, the net present value of capital costs at alternative discount rates was calculated for plants costing 1220, 2000 and 3300 1982 dollars per kilowatt, irrespective of their scale. This gives a range of costs within which the cost of a coal-fired power plant is likely to fall, notwithstanding some major sources of uncertainty described below.

An estimate of the present value of total capital costs that could be attributed to each mine was calculated as follows:

(a) Apply the following proportions to total capital cost per kilowatt in order to derive a cash flow:

1985	.1	
1986	.2	(Note: cash flow based
1987	.2	on 1 January 1990 in-service
1988	.3	date for powerplant.)
1989	.2	
	1.0	

(b) From cash flow, calculate the net present value of total capital cost per kilowatt. These values for alternative cost assumptions and discount rates are given in Figure 3.

(c) Multiply the values given in Figure 3 by the power requirement of each mine to get the presentvalue of total capital cost that could be attributable to each mine. e.g. For a plant costing \$1220/kW, the present value of total cost attributable to Cassiar at an 8% discount rate is \$755/kW X 10 MW = \$7.55 X 10^6.

FIGURE 3

NORTHWEST B.C. DEVELOPMENT STUDY

Matrix of Present Value of capital cost per kilowatt for coal thermal generation at Klappan under alternative assumptions of unit cost (excluding IDC, Corporated Overhead, & Taxes) (1982 $/kW; discounted to 1982)

In-service date: 1990

Discount Rate / Unit Cost of Generation (1982 $/Net kW)	8%	10%	12%
1220	755	674	604
2000	1337	1216	1108
3300	2205	2006	1829

Fuel Cost

It is assumed that the direct cost of mining coal (excluding the cost of financing) is $1.28/million Btu. Using a heating value of 26 348 kJ/kg (air dried basis), this translates into a cost of about $32 per tonne of raw coal.[15]

Alternatively, one might argue that the opportunity cost of coal is the FOB export price of anthracite net of transportation. This is estimated at $75/tonne in 1982 dollars.[16]

Assuming a net plant heat rate of 11 400 kJ/kWh, the above fuel costs translate into the following mill rates for fuel:

	1982 mills/kWh
Cost of mining[17]	14
Opportunity cost of export[18]	32

Operating Cost (Excluding Fuel)

Annual operating, maintenance and project associated administration costs are estimated to be 6 mills/net kWh. It assumed, for study purposes that these costs are independent of scale.

15 This heat content was suggested by Gulf Canada Resources Inc. in their "Mount Klappan Coal Project, Executive Summary", March 1982.

16 $100/t is export price (reference: discussion with Ministry of Industry and Small Business Development); $25/t B. C. Hydro estimated transportation cost.

17 $1.28/Btu X 10^6 ÷ 1.055 kJ/Btu X 11400 KJ/kWh X 10^3 mills/$ = 14 mills/kWh.

18 $75/t ÷ $32/t x 13.8 mills/kWh = 32 mills/kWh.

(v) Major Sources of Uncertainty

No field examination of the project location has been made, no environmental data have been obtained, and no commitments were made by Gulf Canada Resources to provide coal. Therefore, major sources of uncertainty would include the following:

- coal availability, quality and cost;
- plant site suitability - need for piling, grading, etc.;
- cooling make-up water availability and cost;
- meteorological conditions for plume dispersal;
- trace element concerns;
- requirements for licensing, including BCUC hearings, etc.;
- operating difficulties.

The last item is included because there would probably be comparatively small loads during early years of the powerplant's operation. Running large units at low load for extended periods could result in substantial expenditure for auxiliary fuel to stabilize the combustion of the coal. Also prolonged low-load operation could adversely affect the longevity of the turbines and other equipment. Trips could be relatively frequent; with the system envisaged a trip of one unit could adversely affect the other unit. Several smaller generating units would be a better technical solution, but would be more costly; for instance, four 62.5 MW (net) units would be about 50 percent greater in aggregate investment cost than the two 125 MW units. Operating, maintenance and administration costs would also tend to increase with more and smaller generating units.

4.5.2 Transmission

(i) General Description

The transmission network proposed for extensions from Klappan is different in the event that Schaft Creek, Stikine Copper, Adanac or Cassiar mine is supplied by power from Klappan than in the event that none of these mines receives power from Klappan. The transmission network in the former case (reference Map No. 3) consists of a single-circuit 230 kV transmission line from the Klappan coal-fired generating station to a major 230/138 kV switching substation at Stikine. 230 kV transmission would be extended from Stikine to a substation at Telegraph Creek and thence via separate radial 230 kV circuits to the mines at Schaft Creek and Stikine Copper. The proposed Red Chris mine and Eddontenajon could be supplied at 25 kV from a 230/25 kV substation near Ealue Lake. The coal mine load at Klappan and the Sustut mine could be supplied at 138 kV from the Klappan generating station.

For the case where all the mines are supplied from Klappan, the proposed method of supply and associated costs for loads north of the Stikine River are the same for the Mount Klappan generating station as for the extensions from Hydro's grid which were discussed in Section 4.4.

In the event that Schaft Creek, Stikine, Adanac and Cassiar all receive power from a source other than Klappan, a single circuit 138 kV extension from Ealue Lake to Kutcho Creek and from there on to Letain and Eaglehead is proposed instead of the extension via Stikine and Dease Lake which was described above. This network, as opposed to the one above, would include a 138 kV line from Klappan

to Ealue Lake with a common substation with 138/25 kV transformation at Ealue Lake. Finally, the major switching station at Stikine would be eliminated.

Transmission line construction schedules have been adjusted where necessary to coordinate with the 1990 in-service date for the Klappan generating station.

(ii) Basis for Choice of Transmission Corridors

Based on use of a coal-fired plant at Klappan to supply all mines and on the production schedule in Section 3.2, the transmission network proposed will provide supply to the mines at lowest overall transmission cost. The routing selected between Stikine and Sustut is the same as that proposed for extensions from the existing grid and is based on the considerations noted in Section 4.4.2. The routing proposed for supply to Telegraph Creek, and mines at Schaft Creek and Stikine Copper is based on preliminary data assembled in 1981, map studies and discussions with route location engineers familiar with this area. Further field studies would be required to confirm this routing and costs.

For the alternate Klappan development, the 138 kV line corridor for the three mines northwest of Ealue Lake was selected on the basis of map studies. Further work would be required to confirm the preferred corridor.

(iii) Basis for Cost Estimates

All transmission cost estimates for this alternative are based on current unit cost estimates prepared specifically for this study and should be treated as preliminary office

estimates subject to significant change following the completion of future detailed field studies.

(iv) Major Sources of Uncertainty

The major sources of uncertainty listed in connection with extensions from the existing grid are also applicable to this alternative. In general, voltage and frequency regulation will be inferior to that available when connected to the existing grid. The transmission network will also be more susceptible to cascading line outages due to generator forced outages, loss of intermediate transmission elements and sudden loss of major loads. The nature and severity of the problems associated with the operation of an isolated transmission system depends on factors, such as transmission line forced outage rates and load characteristics, which have not been defined at this writing and were not investigated in preparation of this report.

(v) Cost Sensitivity

The comments provided on the sensitivity of costs to likely contingencies with respect to extensions from the existing grid are also applicable to the transmission network proposed for supply from the proposed Klappan generating station.

4.5.3 Supplemental Diesel Generation

Costs are derived in the same way as described in Chapter 4.1, Pages 17-19 except that units are salvaged in 1990 when energy from a thermal power plant becomes available.

5. ECONOMIC ANALYSIS

5.1 Procedure for Determining Least Cost Power Option for Each Mine

As noted on page 7, the average energy cost of some power options depends on the number of mines which share a particular transformation or transmission facility. The procedure described below was developed in order to come up with a least cost power option despite this interdependence between mines.

The procedure used to come up with the least cost power option for each mine is summarized in figure 4. Step 1 in figure 4 compares remote power options. For these, the cost of supplying power to any one mine is determined independently from the cost at any other mine.

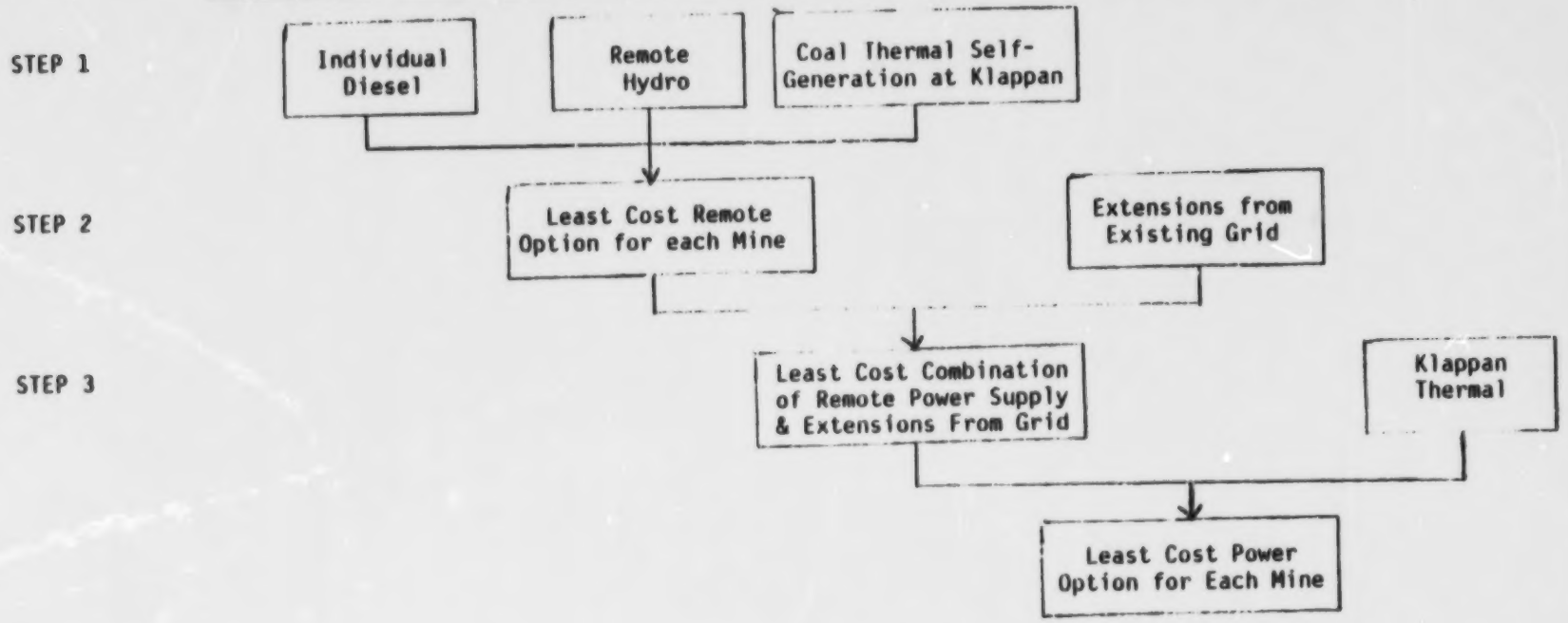
Step 2 compares the least cost remote option for each mine with the cost of extensions from the existing grid. This comparison is distinguished from Step 1 for a number of reasons. First, the cost of extensions from the existing grid varies with assumptions about the availability of power from B. C. Hydro's Stikine/Iskut Project. This implies that Step 2 produces a least cost combination of remote generation and extensions from the grid for each of the three scenarios described in Section 2.1, p. 4. Second, the average energy cost of extensions from the grid varies with the number of mines which use this power option. That is, unlike the options compared in Step 1, the average energy cost of extensions from the grid is not determined independently for each mine.

Step 2 involves a series of iterations because the average energy cost of extensions from the grid varies with the number of mines which share the extensions. For the first iteration, it is assumed that all mines are supplied by extensions from

FIGURE 4

NORTHWEST B. C. DEVELOPMENT STUDY

PROCEDURE FOR SELECTING LEAST UNIT COST POWER SUPPLY OPTION FOR NORTHWEST DEVELOPMENT


STEP 1
Individual Diesel
Remote Hydro
Coal Thermal Self-Generation at Klappan
STEP 2
Least Cost Remote Option for each Mine
Extensions from Existing Grid
STEP 3
Least Cost Combination of Remote Power Supply & Extensions From Grid
Klappan Thermal
Least Cost Power Option for Each Mine

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the existing grid. This implies that the cost of transmission lines and substations which serve more than one mine are divided by a maximum number of mines and therefore impose a lower cost per mine on the economy than would be the case if the facilities were built for fewer mines. The first iteration allows a comparison of the average energy cost of remote power supplies and of the lowest possible cost of extensions from the grid. If, as a result of this first iteration, it appears that for some mines remote power is cheaper than extensions from the grid, then it is assumed that these mines would not use extensions from the grid and that the cost of transmission lines and substations would be shared by fewer mines. A second iteration is done, assuming that those mines which were not dropped after the first round carry the cost of extensions from the grid. With each iteration the average energy cost of extensions from the grid increases. Thus, the process of iterations continues until no more mines drop out and an equilibrium is reached.

Step 3 compares:

(i) the cost of power from a central coal-fired powerplant at Klappan; and

(ii) the least cost combination of remote power and extensions from the existing grid.

As is the case for extensions from the existing grid, the transmission costs which are associated with a central powerplant at Klappan are dependent upon the number of mines which are supplied from the plant. The effect of reducing the number of mines which would share proposed transmission facilities from Klappan is not trivial. Therefore, a series of iterations, as described above for Step 2, are required in order to come up with an average energy cost estimate for the Klappan thermal option.

Because of the lengthy process of iterations to come up with average energy costs for transmission, only one combination of operating and capital costs for Klappan thermal is worked through here. This is capital cost of $2000/kW and total operating cost of 20 mills/kWh.

Two other cases are briefly examined in order to provide perspective. These are:

(i) the high end of our cost range with capital cost of $3300/kW and total operating cost of 38 mills/kWh; and
(ii) the low end of our cost range with capital cost of $1220/kW and total operating cost of 20 mills/kWh.

These two cases are examined to gain insight into whether the thermal option would be cost effective at some point within a wide range of costs and hence, whether it appears worthwhile to undertake detailed cost studies.

5.2 Results

Tables 6-12 at the end of this chapter give the average energy cost (AEC) of alternative power options. These tables are set up so that they correspond to the procedure for cost analysis summarized in Figure 4. Table 6 corresponds to Step 1 in Figure 4; tables 7-9 to Step 2; and tables 10-12 to Step 3. The purpose of this section is to provide a detailed discussion of power costs at each mine. A summary is given in Chapter 7, p. 85.

Before discussing results in detail, the following points are worth noting:

(a) The average B. C. Hydro industrial rate for the 1990's is expected to be roughly 25 mills/kWh in constant 1982 dollars (ref. p. 38). This value provides a benchmark against which to compare the costs in this chapter.

(b) The in-service date of Hydro's Stikine/Iskut Development affects the ranking of power options at many of the mines. Note that one cannot infer from this that it makes economic sense to advance construction of the entire Stikine/Iskut Development to provide power for mines in the Northwest. However, one can infer that high initial capital costs associated with supplemental diesel generation and advanced construction of facilities associated with Hydro's Stikine/Iskut development could be reduced by deferring mine start-up dates so that they correspond to the availability of Stikine/Iskut power for the economy as a whole.

(c) It is likely that some of the dates, both for mine start-up and for power availability, are optimistic. However, average energy costs are affected only by the number of years between start-up schedules. That is, results are unaffected if both the start-up year for mines and the in-service date for a source of power are shifted back by the same number of years. (ref. discussion in Section 2.3, pp. 6-7.)

5.2.1 Cassiar

Diesel is the least-cost power option at Cassiar. It is less expensive than small hydro mainly because existing diesel units are assumed to be operatable until the mine

is scheduled to close in 1995. This means that, in contrast to the other mines, the cost of diesel power at Cassiar includes only operation and maintenance and not fixed asset expenditure.

The cost of transmission from Dease Lake northward to Cassiar exceeds the cost of diesel. This is true even if the transmission costs are split between Cassiar and Adanac. Since extensions northward from Dease Lake to Cassiar are required to transmit power from any source of generation south of Dease Lake (including the Stikine/Iskut Development and a coal-fired powerplant at Klappan) one can infer that, for Cassiar, the AEC of remote power is less than the AEC of any other option considered in this study.

5.2.2 Adanac

Just like at Cassiar, the cost of transmission from Dease Lake northward to Adanac alone precludes all the power options except small hydro and diesel.

The AEC of small hydro at Adanac is lower than the AEC both of diesel and of small hydro generation at the other mines (reference Table 6). There are two factors which, in combination, make small hydro a particularly attractive option at Adanac. These are:

(i) expected mine life is long (20 years) relative to some of the other mines. This tends to make the AEC at Adanac lower both because "up-front" capital costs at small hydro sites are much more significant than operating costs and because the salvage value of generation facilities is relatively small;

(ii) the site identified near Adanac has storage whereas others such as Red Chris and Sustut have run-of-the-river generators. The latter are more expensive because they require a greater installed capacity of supplementary diesel units than the storage plants do.

5.2.3 Klappan

On-site generation using a coal-fired powerplant is likely to be the least-cost power option at Klappan unless the start-up date of the mine is delayed until power from Hydro's Stikine/Iskut development becomes available.

The following rationale underlies this conclusion:

With mine start-up dates and power options considered in this study, coal-fired generation is the least-cost source of power at Klappan unless power is available from Hydro's Stikine/Iskut development by 1995 and the cost of a coal-fired powerplant is near the top of our range of cost estimates (ref. Section 4.5, pages 49 & 52). This is an unlikely combination, not least because the top end of the cost range is conservative and therefore the actual cost is likely to be lower.

If the start-up date for Klappan is delayed until power becomes available from Hydro's Stikine/Iskut project, then an extension from Stikine to Klappan becomes a potentially attractive option. The AEC cost of power from the Stikine/Iskut Development (with transmission facilities built solely for the use of Klappan mine) ranges from 42 mills/kW.h at 8% to 61 mills/kW.h at 12%. Especially at low discount

rates, this compares favourably with the cost of coal-fired generation (ref. Table 6).

5.2.4 Sustut

If the cost of a coal-fired powerplant at Klappan falls within the range of costs assumed in this report, then diesel is the least cost power option at Sustut.

One explanation of the difference between the AEC of remote and central coal-fired power is that the cost of building a coal-fired plant by 1990 (as assumed for economic analysis; see p. 48) falls on Sustut even though Sustut is not scheduled to open until 1996. As shown below, if the start-up date were 1990 instead of 1996, diesel would still be preferred, but by a much smaller margin.

Average Energy Cost
(1982 mills/kW.h)

	Discount Rate		
	8%	10%	12%
Power Option			
Diesel	125	127	128
Coal-Fired Thermal			
- with Sustut opening 1996	154	172	190
- with Sustut opening 1990	135	145	153

The AEC of small hydro at Sustut is high relative to all other mines except Red Chris. The following three factors contribute to this outcome:

(i) The scheduled life of Sustut mine is only eight years. As explained above (viz. Section 5.5.2) this tends to push up the AEC of small hydro plants in isolated areas such as Sustut where they cannot be used after mine closure to supply other power requirements;

(ii) Sustut would use a run-of-the-river plant. This type of plant requires greater installed capacity of supplementary diesel than plants with capacity to store water; and

(iii) The identified hydro site would provide only 3 of the 10 MW of mine load. Therefore, the supplementary diesel requirement is almost equivalent to the "diesel only" option.

Finally, the AEC of an extension from Hydro's grid is more expensive than the diesel option because of the remoteness of Sustut.

However, if Sustut were to open when power was available from Hydro's Stikine/Iskut Development then an extension from Hydro's substation at Stikine to Sustut might compare favourably with the diesel option. This would depend on arrangements for financing the extension.

If the extension were built solely for Sustut, then it would be less economical than diesel. Moreover, if the cost of the line from Stikine to Klappan were divided equally between Sustut and Klappan mines, then diesel would still be more economical.

However, if the extension from Stikine to Klappan is borne by Klappan mine, then the AEC of power from the Stikine substation plus the AEC of transmission from Klappan to Sustut would be about 10 - 20 mills/kW.h less than the AEC of diesel at 10% and 8% discount rates respectively. At 12% the difference disappears.

In short, if most of the cost of an extension from Stikine to Klappan is born by Klappan mine, then it may be possible to come up with a cost-sharing arrangement which would make power from Hydro's Stikine/Iskut Development an attractive option. Otherwise, diesel has the lowest AEC.

5.2.5 Red Chris

The choice of a least cost power option at Red Chris cannot be determined unequivocally. Rather, it depends on:

(i) the availability of power from Hydro's Stikine/Iskut Development;

(ii) the schedule of mine start-up dates;

(iii) the number of mines which share a particular transmission or generation facility;

(iv) the discount rate; and

(v) the order of magnitude of the cost of a coal-fired powerplant.

Under the following two cost scenarios, coal-fired power from Mount Klappan to serve Red Chris would be the least cost option. First, if coal-fired generation has a capital cost of $2000/kW and operating cost of 20 mills/kWh (i.e. roughly mid-range of our estimates), then a coal-fired powerplant is the preferred option regardless whether the in-service date of Hydro's Stikine/Iskut project is 1995, 2000 or indefinite.

Second, even if the cost of coal-fired generation is at the top of our range of estimates, it still has the lowest AEC at an 8% discount rate if the in-service date of the Stikine/Iskut project is the year 2000 or later. If the discount rate is 10% or 12% or, alternatively, if Stikine/Iskut power is available by 1995, then either diesel or an extension from Hydro's grid becomes the least-cost option. The choice between these two options again depends on the 5 factors listed above.

The assumption that the in-service date of Red Chris is fixed underlies the above conclusion. If in fact its start-up date is delayed until power from Hydro's Stikine/Iskut Development becomes available, then this would become the least cost power option. Even if the entire cost of a transformation station at Stikine as well as transmission from Stikine to Red Chris is borne by this one mine, the AEC of Stikine/Iskut power ranges from roughly 65 mills/kW.h at 8% to 90 mills/kW.h at 12%. This is less than the cost of any of the other options that were examined.

5.2.6 Kutcho Creek, Letain and Eaglehead

Similar to Red Chris, the choice of a least-cost power option at these mines cannot be determined unequivocally and it depends on the 5 factors listed above in Section 5.2.5.

At the high end of the range of cost estimates for coal-fired generation, diesel is the least cost option at all three mines. However, depending on its cost, a coal-fired powerplant at Klappan may be an attractive option. For example, with the mid-range cost estimates used in tables 10-12, coal-fired generation is the least-cost option at all 3 mines. As noted in Section 2.2, p. 8, of the entire cost of transmission from Klappan to Eaglehead, only the cost of an extension from Letain to Eaglehead is allocated to the latter. As explained below, this is done in order to avoid an improbable ranking of power options at Eaglehead.

If transmission costs were divided equally between all mines, then at 10% to 12% dicount rates diesel would be the least cost option at Eaglehead and central coal-fired generation would be the least cost option at Red Chris, Klappan, Kutcho Creek and Letain. This implies that a transmission line from a coal-fired powerplant to Letain would exist independently of the power option selected at Eaglehead. With an existing transmission line as far as Letain, the sum of the cost of coal-fired generaton and transmission from Letain to Eaglehead make power from a coal-fired powerplant a more attractive option than diesel at Eaglehead. Therefore, it is conceivable that a cost sharing arrangement could be worked out whereby for all mines involved the least cost power option would include Eaglehead using power from a central coal-fired powerplant

at Klappan as long as Kutcho Creek and Letain do so as well.

Again, as for all the mines discussed above, the least cost power option depends crucially on mine start-up dates. For these three mines in particular, the assumption about start-up dates effects the choice of power option in two ways. These are discussed in turn.

First, if power were not required until it became available from Hydro's Stikine/Iskut Development, then an extension from Stikine substation to the mines would likely be the most economical option for all three mines. This is the case even if one assumes that each mine bears the entire cost both of transformation at Stikine substation and of the transmission line from Stikine to the mine. The AEC would be lower if mines shared these transmission facilities.

The second way in which the results of this study would change if mine start-up dates were different is as follows.

The AEC of the shared small hydro facility at Kutcho Creek, Letain and Eaglehead is biased upward relative to the cost of diesel because the facility is assumed to start operation in 1987 when Kutcho Creek is scheduled to open even though the other two mines are not scheduled to start up until 1990 and 1995 respectively. If all three mines had the same start-up date, then the AEC for supplying them with power from small hydro generation would be lower; in particular:

Discount Rate	AEC (1982 mills/kWh)	
	same start-up date	different start-up dates (ref. Table 6)
8%	101	130
10%	115	153
12%	129	179

For all three mines this would change the ranking between diesel and small hydro. It would make the AEC for small hydro less than the AEC for diesel (by more than 10% at 8 and 10% discount rates and by less than 10% at a 12% discount rate).

In summary, many factors make it impossible to say at this stage what the least cost power option will be for Kutcho Creek, Letain and Eaglehead. However, it is certain that the choice at each mine is not independent. The mines are so close to one another that a choice by any one mine will affect the choice made by the other two.

5.2.7 Schaft Creek

It is likely that advanced construction of More Creek would be the least cost power option for Schaft Creek unless the start-up date of the mine is delayed until power is available from Hydro's Stikine/Iskut Development.

If the start-up date is delayed then the AEC of Stikine/Iskut power ranges from approximately 30 mills/kWh at 8% to 45 mills/kWh at 12% with the entire cost of a 230 kV termination substation at Bob Quinn as well as the cost of transmission from Bob Quinn to Schaft Creek being borne by

this one mine. This is less than the cost of advancing More Creek (ref. Table 6).

Conversely, if the proposed mine start-up date is fixed, then under a mid-range estimate for the cost of a coal-fired powerplant (see Tables 10-12), advanced construction of More Creek is more attractive than other power options for all three scenarios of Stikine/Iskut in-service dates (scenarios defined on p. 5). However, at both the high and low ends of our range of cost estimates, the result is less clear-cut. Therefore, these two extremes are considered in turn.

If the cost of a coal-fired powerplant approaches the top of the cost range then extensions from the grid become an attractive option for some of the mines, but only at an 8% discount rate and assuming a 1995 in-service date for the Stikine/Iskut development. In other words, at a low discount rate, the cost of advancing construction of the transmission associated with Hydro's Stikine/Iskut Development is low enough to provide an attractive option as long as the cost of the transmission line is shared by most of the mines and as long as the cost of coal-fired generation approaches the top of our range of cost estimates. It is unlikely that this combination of conditions will be met and, therefore, it follows that an extension from Hydro's grid is unlikely to be cheaper than advancing construction of More Creek.

If the cost of coal-fired generation is at the bottom of our range of cost estimates, More Creek remains, with one possible exception, the most economical option.

The possible exception arises if More Creek supplies both Schaft Creek and Stikine Copper rather than just the former. The in-service date of the Stikine/Iskut Development determines whether More Creek would supply power to one or both mines. With an indefinite in-service date, it is assumed that More Creek supplies both mines. This option, unlike the other, requires the installation of supplemental diesel units and these make the AEC of More Creek power greater than the AEC of coal-fired generation. Conversely, the AEC of advanced More Creek is less than the AEC of coal-fired generation if More Creek supplies Schaft Creek alone rather than both mines.

If the Stikine/Iskut Development is built at all, then it is unlikely that More Creek would be advanced for both Schaft Creek and Stikine Copper. The rationale underlying this conclusion is based on two factors. First, there is an incentive to delay the opening of Stikine Copper until power is available from Hydro's Stikine/Iskut Development because this option has by far the lowest AEC. Second, the late start-up date proposed for Stikine Copper (i.e. 2000) seems to indicate that plans for developing the mine are tentative and may therefore permit delay of the start-up date until power becomes available from the Stikine/Iskut development.

In summary, it is likely that advanced More Creek will be the least cost power option at Schaft Creek if the mine's start-up date is fixed; especially if power from Hydro's Stikine/Iskut development is available before the turn of the century. However, if the start-up date of the mine is delayed until power from the Stikine/Iskut Development is available, then this would become the least cost option.

5.2.8 Stikine Copper

As long as power from Hydro's Stikine/Iskut development is available by the time the mine opens (proposed date is 2000), then an extension from the mine to Hydro's Bob Quinn Substation would be the least-cost power option.

Alternatively, if the in-service date of the Stikine/Iskut Development is indefinite then the next best option is to share the cost of advanced More Creek with Schaft Creek mine.

TABLE 6
NORTHWEST B. C. DEVELOPMENT STUDY

AVERAGE ENERGY COST OF ALTERNATIVE REMOTE POWER OPTIONS, BY MINE
(mills/kWh; excluding interest during construction, corporate overhead & taxes)

Power Option:	Individual Diesel (Light Fuel Oil unless marked)			Remote Hydro (More Creek & small hydro)			Coal-Thermal Self-Generation at Klappan		
Discount Rate:	8%	10%	12%	8%	10%	12%	8%	10%	12%
Cassiar	109	109	109	120	126	132			
Kutcho Creek	125	127	129	130	153	179			
Letain	128	131	134	130	153	179		N/A	
Eaglehead	128	131	134	130	153	179			
Adanac	114	115	116	90	98	106			
Red Chris	128	132	135	175	195	215			
Sustut	125	127	128	162	169	174			
Klappan	104[3]	109[3]	115[3]	N/A[1]	N/A[1]	N/A[1]	41-96[2]	44-107[2]	48-118[2]
Schaft Creek[4]									
(i) no Stikine/Iskut project	101	107	113	53	64	76			
(ii) S/I proj. in-service in 2000	101[3]	107[3]	113[3]	38	49	62			
(iii) S/I proj. in-service in 1995	101	107	113	33	42	53			
Stikine Copper[4]								N/A	
(i) no Stikine/Iskut project	100[3]	105[3]	110[3]	91	108	127			
(ii) with S/I project	100[3]	105[3]	110[3]	N/A	N/A	N/A			
Schaft Creek & Stikine Cu.[4] sharing More Creek (no S/I Project)	N/A	N/A	N/A	60	69	79			

1 No Hydro site identified near Klappan.
2 Range of costs represents: (a) capital and total operating costs of $1220/kW and 20 mills/kWh respectively; and (b) capital and total operating costs of $3300/kW and 38 mills/kWh respectively.
3 Heavy fuel oil.
4 Refer to discussion on pp 29-31.

TABLE 7
NORTHWEST B. C. DEVELOPMENT STUDY
LEAST COST COMBINATION OF REMOTE POWER SUPPLY AND
EXTENSIONS FROM EXISTING GRID AT ALTERNATIVE DISCOUNT RATES
NO STIKINE/ISKUT DEVELOPMENT

Mine	Least Cost Power Option	Average Energy Cost (1982 mills/kW.h; excluding interest during construction, corporate overhead and taxes) 8%	10%	12%
Cassiar	Diesel	109	109	109
Kutcho Creek	Diesel	125	127	129
Letain	Diesel	128	131	134
Eaglehead	Diesel	128	131	134
Adanac	Small Hydro	90	98	106
Red Chris	Diesel	128	132	135
Sustut	Diesel	125	127	128
Klappan	Coal-fired self-generation	40-96[1]	43-107[1]	47-118[1]
Schaft Creek	More Creek	60	69	79
Stikine Copper	More Creek	60	69	79

[1] Range:

(a) Low - Capital cost $1220/kW and total operating cost 20 mills/kWh;
(b) High - Capital cost $3300/kW and total operating cost 38 mills/kWh.

TABLE 8
NORTHWEST B. C. DEVELOPMENT STUDY
LEAST COST COMBINATION OF REMOTE POWER SUPPLY AND
EXTENSIONS FROM EXISTING GRID AT ALTERNATIVE DISCOUNT RATES
STIKINE/ISKUT DEVELOPMENT IN-SERVICE IN 2000

Mine	Least Cost Power Option	Average Energy Cost (1982 mills/kW.h; excluding interest during construction, corporate overhead and taxes) 8%	10%	12%
Cassiar	Diesel	109	109	109
Kutcho Creek	Diesel	125	127	129
Letain	Diesel	128	131	134
Eaglehead	Diesel	128	131	134
Adanac	Small Hydro	90	98	106
Red Chris	Diesel	128	132	135
Sustut	Diesel	125	127	128
Klappan	See fn.	40-82	43-99	47-116
Schaft Creek	Advanced More Creek	38	49	62
Stikine Copper	Extension from grid (i.e. from Bob Quinn Substation)	35	44	58

fn. Low end of range is cost of coal-fired self-generation at Klappan. High end of range is cost of extension from grid. The high end of range is close to the high end of the range of costs for coal-fired generation (see Table 6).

TABLE 9
NORTHWEST B. C. DEVELOPMENT STUDY
LEAST COST COMBINATION OF REMOTE POWER SUPPLY AND
EXTENSIONS FROM EXISTING GRID AT ALTERNATIVE DISCOUNT RATES
STIKINE/ISKUT DEVELOPMENT IN-SERVICE IN 1995

Mine	Average Energy Cost (1982 mills/kW.h; excluding interest during construction, corporate overhead and taxes) 8%	10%	12%
Cassiar	109[D]	109[D]	109[D]
Kutcho Creek	114[EG]	127[D]	129[D]
Letain	80[EG]	131[D]	134[D]
Eaglehead*	91[EG]	131[D]	134[D]
Adanac	90[SH]	98[SH]	106[SH]
Red Chris	87[EG]	132[D]	135[D]
Sustut	125[D]	127[D]	128[D]
Klappan	53[fn]	62[CT]	69[CT]
Schaft Creek	29[EG]	42[MC]	53[MC]
Stikine Copper	35[EG]	44[EG]	58[EG]

* Note basis for cost calculation; discussed on p. 68.
D Diesel (light fuel oil).
SH Small Hydro.
MC Advanced More Creek.
CT Coal-fired self-generation (mid-range cost estimate; i.e. capital cost of $2000/kW and total operating cost of 20 mills/kWh).
EG Extensions from B. C. Hydro grid.
fn Choice depends on cost of coal-fired self-generation at Klappan. Costs given here are the cost of a coal-fired plant with capital cost of $2000/kW and operating cost of 20 mills/kWh. The cost of an extension from B. C. Hydro's grid is almost identical.

TABLE 10
NORTHWEST B. C. DEVELOPMENT STUDY
LEAST COST POWER OPTION AT ALTERNATIVE DISCOUNT RATES, ASSUMING THAT COAL-FIRED GENERATION HAS CAPITAL COST OF $2000/kW AND OPERATING COST OF 20 mills/kWh
NO STIKINE/ISKUT DEVELOPMENT

Mine	Least Cost Power Option	Average Energy Cost (1982 mills/kWh; excluding interest during construction, corporate overhead and taxes) 8%	10%	12%
Cassiar	Diesel	109	109	109
Kutcho Creek	Coal-fired thermal	118	125	128
Letain	Coal-fired thermal	97	108	112
Eaglehead*	Coal-fired thermal	85	102	122
Adanac	Small Hydro	90	98.	106
Red Chris	Coal-fired thermal	75	85	96
Sustut	Diesel	125	127	128
Klappan	Coal-fired thermal	53	60	67
Schaft Creek	More Creek	60	69	79
Stikine Copper	More Creek	60	69	79

* Note basis for cost calculation; discussed on pp. 68.

TABLE 11
NORTHWEST B. C. DEVELOPMENT STUDY
LEAST COST POWER OPTION AT ALTERNATIVE DISCOUNT RATFS, ASSUMING THAT COAL-FIRED GENERATION HAS CAPITAL COST OF $2000/kW AND OPERATING COST OF 20 mills/kWh STIKINE/ISKUT DEVELOPMENT IN-SERVICE IN 2000

Mine	Least Cost Power Option	Average Energy Cost (1982 mills/kW.h; excluding interest during construction, corporate overhead and taxes) 8%	10%	12%
Cassiar	Diesel	109	109	109
Kutcho Creek	Coal-fired thermal	118	125	128
Letain	Coal-fired thermal	97	108	112
Eaglehead*	Coal-fired thermal	85	102	122
Adanac	Small Hydro	90	98	106
Red Chris	Coal-fired thermal	75	85	96
Sustut	Diesel	125	127	128
Klappan	Coal-fired thermal	53	60	67
Schaft Creek	Advanced More Creek	38	49	62
Stikine Copper	Extension from grid (i.e. from Bob Quinn Substation)	35	44	58

* Note basis for cost calculation; discussed on p. 68.

TABLE 12
NORTHWEST B. C. DEVELOPMENT STUDY
LEAST COST POWER OPTION AT ALTERNATIVE DISCOUNT RATES, ASSUMING THAT COAL-FIRED GENERATION HAS CAPITAL COST OF $2000/kW AND OPERATING COST OF 20 mills/kWh
STIKINE/ISKUT DEVELOPMENT IN-SERVICE IN 1995

Mine	Average Energy Cost (1982 mills/kW.h; excluding interest during construction, corporate overhead and taxes)		
	8%	10%	12%
Cassiar	109^{D}	109^{D}	109^{D}
Kutcho Creek	118^{CT*}	125^{CT}	128^{CT}
Letain	97^{CT*}	108^{CT}	112^{CT}
Eaglehead**	85^{CT*}	102^{CD}	122^{CT}
Adanac	90^{SH}	98^{SH}	106^{SH}
Red Chris	75^{CT*}	85^{CT}	96^{CT}
Sustut	125^{D}	127^{D}	128^{D}
Klappan	53^{CT*}	60^{CT}	67^{CT}
Schaft Creek	33^{MC*}	42^{MC}	53^{MC}
Stikine Copper	35^{EG}	44^{EG}	58^{EG}

* Choice between cost of the least expensive option and extension from grid depends crucially on the cost of coal-fired generation. N.B.: Some of these costs are higher than the ones shown in Table 9. This is because of the inverse relationship between the number of mines which use a transmission line and the average energy cost of the line.
** Note basis for cost calculation; discussed on p. 68.
D Diesel (light fuel oil).
MC Advanced More Creek.
SH Small Hydro.
CT Coal-fired thermal.
EG Extension from B. C. Hydro grid.

6. INSTITUTIONAL ARRANGEMENTS

The following points are of concern to B. C. Hydro and have arisen during discussions about possible institutional arrangements for power supply to mines in the Northwest.

6.1 Adanac (Small Hydro)

(a) B. C. Hydro is not opposed in principle to large industrial customers developing local, small hydroelectric facilities for their electric load. Conflicts may arise if B. C. Hydro wants to develop the same site to displace diesel generation in an existing community.

(b) Depending on particular circumstances B. C. Hydro may be prepared to assist industry in the Northwest to identify small, local hydroelectric sites for examination.

(c) B. C. Hydro's policy with respect to purchasing power from small privately owned hydroelectric generation facilities is unlikely to become an issue in conjunction with this study. This is because Adanac is the only mine for which small hydro is an economic source of power, but this mine requires more power than is available from the small Hydro site. Therefore, it is unlikely that B. C. Hydro would have the option of purchasing power from Adanac.

6.2 Questions have been raised about the feasibility of:

(a) developing More Creek for local area development without connection to the integrated system; and

(b) prebuilding transmission lines from the Stikine/Iskut region to the existing grid for local area development.

Answers to those questions are beyond the scope of this study for two reasons:

(a) the feasibility from the point of view of the Province as a whole requires consideration of benefits and costs other than the cost of power; and

(b) the feasibility from the point of view of B. C. Hydro requires analysis both of possible pricing arrangements and of costs, including corporate overhead, interest during construction, water licence fees and other taxes and grants. As noted in Chapter 2, page 6, these costs are excluded from the economic analysis of this report in order to reflect costs to the economy as a whole rather than the redistribution of resources between different sectors of the economy.

7. CONCLUSIONS AND RECOMMENDATIONS

7.1 General Conclusions About Ranking of Power Options

7.1.1 There is no single preferred power option for all mines in the northwest.

7.1.2 The average energy cost of some power options is biased upward for mines where supplemental diesel generation is required because the start-up date of the mine precedes the earliest feasible in-service date for another source of power.

7.1.3 In general, diesel generation is preferred to small hydro as an on-site source of electricity. The exception in this study was Adanac, where a particularly favourable hydro site was identified. Note that this general relationship may be reversed if constant dollar diesel prices increase significantly.

7.1.4 Advanced construction of transmission facilities from Hydro's existing grid to the mines is probably not an economic option.

7.1.5 Power from a central coal-fired powerplant at Klappan becomes more attractive as the in-service date of the Stikine/Iskut Development is deferred relative to the fixed start-up dates for the mines.

7.2 Ranking of Power Options at Individual Mines

7.2.1 The cost of transmission north of Dease Lake alone exceeds the cost of generating power at or near Cassiar and Adanac. Therefore, notwithstanding the possibility of extending transmission facilities southward from the Yukon

to Adanac and Cassiar, it appears that small hydro plus diesel at Adanac and diesel at Cassiar are the least-cost power options.

7.2.2 If the cost of a coal-fired powerplant at Klappan falls within the range of costs assumed in this report, then diesel is the least-cost power option for Sustut.

7.2.3 Advanced construction of Hydro's More Creek Project is likely to be the least-cost power option for Schaft Creek.

7.2.4 Stikine Copper is scheduled to open in the year 2000. Extensions from the grid at Bob Quinn Substation would be by far the least-cost power option for Stikine Copper if the mine opens after power is available from B. C. Hydro's Stikine/Iskut Development.

7.2.5 On-site coal-fired generation is likely to be the least cost power option for Klappan mine. However, if the in-service date of the mine is delayed until power becomes available from Hydro's Stikine/Iskut Development then an extension from the Stikine/Iskut Development may be the preferred option.

7.2.6 Factors which are likely to influence the preferred power option at other mines include:

(a) the availability of power from Hydro's Stikine/Iskut Development;
(b) the schedule of mine start-up dates;
(c) the number of mines which share a particular transmission or generation facility;
(d) the discount rate; and
(e) the approximate cost of a coal-fired powerplant.

7.2.7 In summary, if the discount rate is between 8% and 12% and if Hydro's Stikine/Iskut Development is in-service either by 1995, 2000 or not at all, then with fixed mine start-up dates the average energy cost for each mine is likely to be in the following ranges:

Summary Table

Mine	Average Energy Cost (1982 mills/kWh)	Least Cost Power Option
Cassiar	110	diesel
Kutcho Creek[19]	110-130	no single least cost option
Letain[19]	80-135	no single least cost option
Eaglehead[19]	85-135	no single least cost option
Adanac	90-110	small hydro
Red Chris	75-135	no single least cost option
Sustut	125-130	diesel
Klappan	40-120	coal-fired thermal
Schaft Creek	30-80	advanced More Creek
Stikine Copper	35-80	extensions from the grid (or advanced More Creek if Stikine/Iskut Project not in service before mine opens)

7.2.8 If mine start-up dates are delayed until power is available from Hydro's Stikine/Iskut Development then this would likely be the least cost power option for all mines except Adanac, Cassiar and under certain conditions, Sustut as well.

[19] Note basis for cost calculation; ref. discussion on p. 68.

7.3 Recommendations

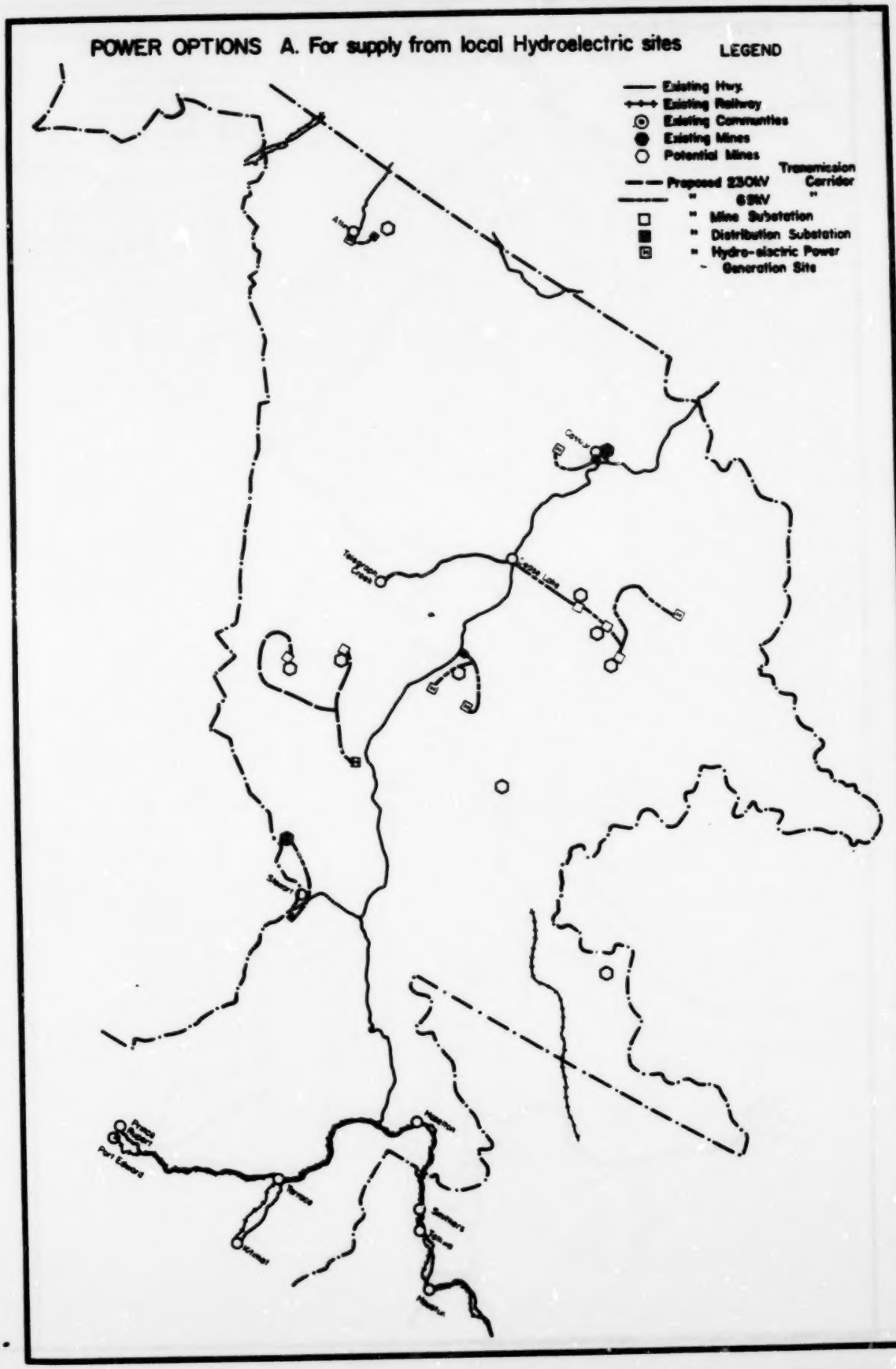
7.3.1 Before refining estimates of power supply costs any further, the economic feasibility of mines should be analysed on the basis of costs given in this report. In particular the sensitivity of mine development to energy costs should be examined. This is important because large distances between mines make power costs at least as sensitive to the number of mines which share transmission facilities as to other factors which affect the cost estimates.

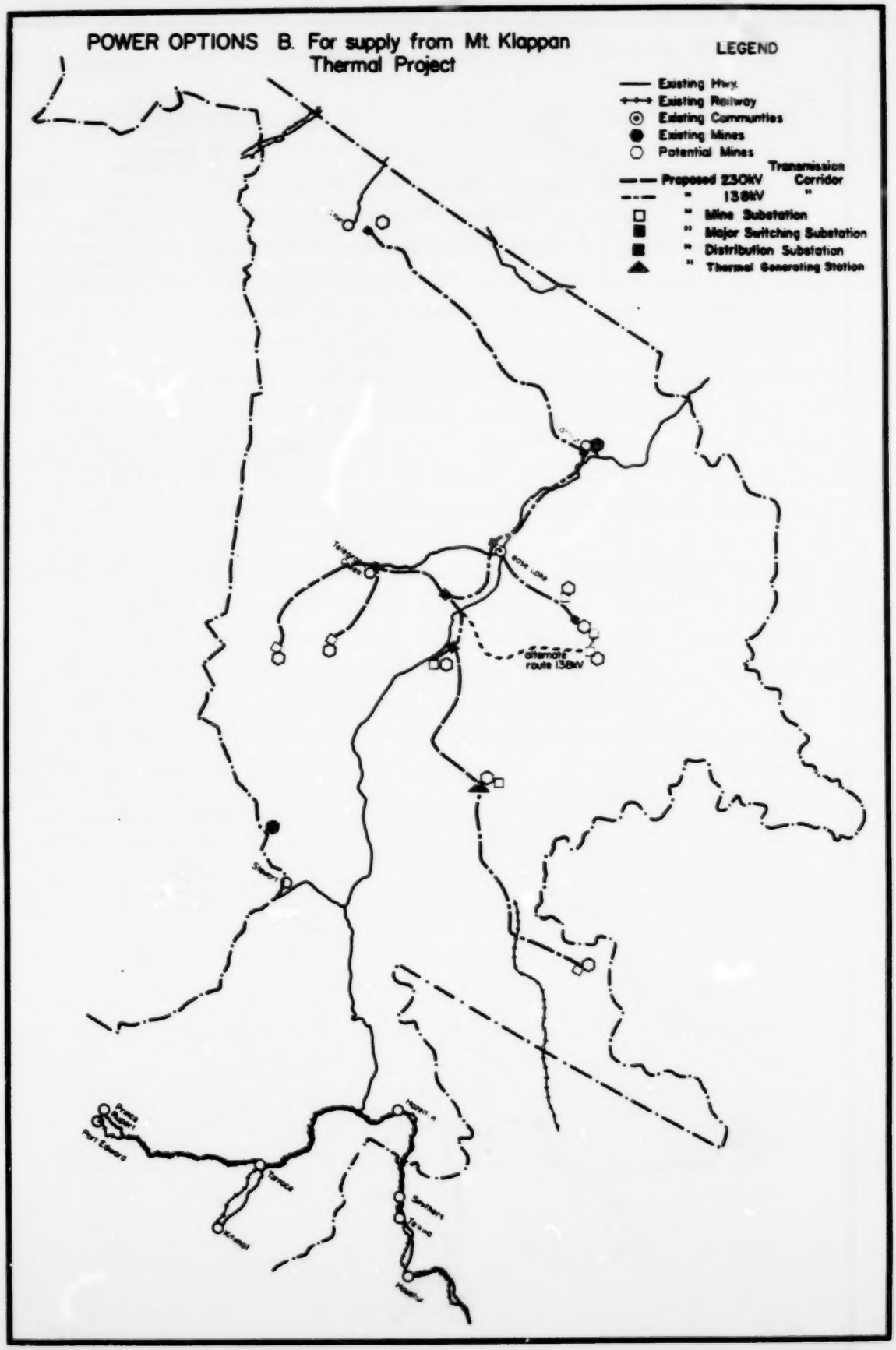
7.3.2 Power options which appear to merit futher study are:

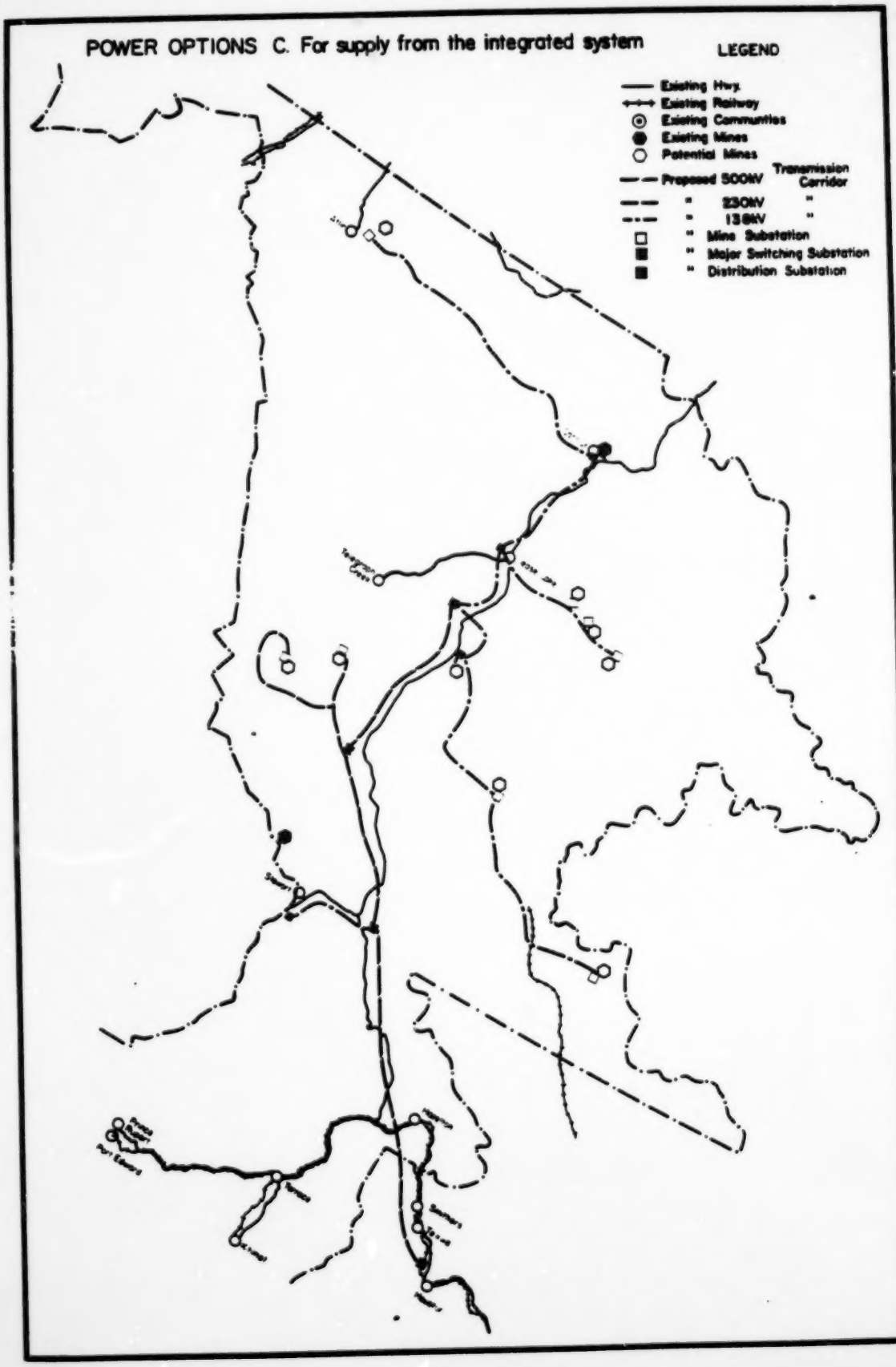
(a) Advancement of Hydro's More Creek Project to serve either Schaft Creek or Stikine Copper.

(b) Partial construction of Hydro's Stikine/Iskut Development to serve Hydro's integrated system as well as Northern mines; and

(c) Development of a coal-fired powerplant at Klappan.


POWER OPTIONS A. For supply from local Hydroelectric sites
LEGEND
Existing Hwy.
Existing Railway
Existing Communities
Existing Mines
Potential Mines
Transmission Corridor
Proposed 230kV "
69kV "
" Mine Substation
" Distribution Substation
" Hydro-electric Power Generation Site


POWER OPTIONS B. For supply from Mt. Klappan Thermal Project
LEGEND
Existing Hwy.
Existing Railway
Existing Communities
Existing Mines
Potential Mines
Transmission Corridor
Proposed 230kV "
" 138kV "
" Mine Substation
" Major Switching Substation
" Distribution Substation
" Thermal Generating Station
alternate route 138kV


POWER OPTIONS C. For supply from the integrated system
LEGEND
Existing Hwy.
Existing Railway
Existing Communities
Existing Mines
Potential Mines
Proposed 500kV Transmission Corridor
" 230kV "
" 138kV "
" Mine Substation
" Major Switching Substation
" Distribution Substation